

UTAH DIVISION OF AIR QUALITY
NEW SOURCE PLAN REVIEW

Clark M. Mower
NEVCO Energy Company, LLC
620 South Main Street
Bountiful, Utah 84010

Project fee code: N2529-001

RE: Sevier Power Company's 270 MW Coal-Fired Power Plant
Sevier County, CDS A; ATT; PSD; NSPS, MACT, HAPs, TITLE
IV MAJOR, TITLE V MAJOR

REVIEW ENGINEER: John D. Jenks

DATE: December 23, 2003

NOTICE OF INTENT SUBMITTED: January 29, 2003

PLANT CONTACT: Clark M. Mower

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SOURCE LOCATION: Northwest of Sigurd, Utah, bordering Highway 89.
Sevier County

UTM COORDINATES: 4,299.9 km. Northing, 414.9 km. Easting, Zone 12
UTM datum NAD27

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REVIEWS:

Peer Engineer _____
Milka Radulovic

DAQ requests that a company/corporation official read the attached draft/proposed Plan Review with Recommended Approval Order Conditions. If this person does not understand or does not agree with the conditions, the PLAN REVIEW ENGINEER should be contacted within five days after receipt of the Plan Review. Special attention needs to be addressed to the Recommended AO Conditions because they will be recommended for the final AO. If this person understands and the company/corporation agrees with the Plan Review or Recommended AO Conditions, this person should sign below and return (can use FAX # 801-536-4099) within 10 days after receipt of the conditions. If the Plan Review Engineer is not contacted within 10 days, the Plan Review Engineer shall assume that the Company/Corporation official agrees with this Plan Review and will process the Plan Review towards final approval. A 30-day public comment period will be required before the Approval Order can be issued.

Thank You

Applicant Contact _____
(Signature & Date)

OPTIONAL: In order for this Source Plan Review and associated Approval Order conditions to be administratively included in your Operating Permit (Application), the Responsible Official as defined in R307-415-3, must sign the statement below and the signature above is not necessary. THIS IS STRICTLY OPTIONAL! If you do not desire this Plan Review to be administratively included in your Operating Permit (Application), only the Applicant Contact signature above is required. Failure to have the Responsible Official sign below will not delay the Approval Order, but will require a separate update to your Operating Permit Application or a request for modification of your Operating Permit, signed by the Responsible Official, in accordance with R307-415-5a through 5e or R307-415-7a through 7i.

“Based on reasonable inquiry, I certify that the information provided for this Approval Order has been true, accurate and complete and request that this Approval Order be administratively amended to the Operating Permit (Application).”

Responsible Official _____
(Signature & Date)

TYPE OF IMPACT AREA

Attainment Area..... Yes
Non-attainment Area
 PM₁₀No
 SO₂.....No
 CO.....No
Maintenance Area
 Ozone.....No
 CO.....No

NSPS Yes
 40 CFR Part 60, Subparts A, Da and Y
NESHAP.....No

MACT Yes
 40 CFR Part 63 Subparts A and case-by-case MACT

Hazardous Air Pollutants (HAPs) Yes
Hazardous Air Pollutants Major Source..... Yes

New Major Source..... Yes
Major Modification.....No
PSD Permit Yes
PSD Increment (modeling) Yes

Operating Permit Program
 MinorNo
 Major Yes

Send to EPA..... Yes
Comment period 30-days

Abstract

NEVCO Energy Company LLC has submitted a Notice of Intent (NOI) to construct and operate a 270 MW Circulating Fluidized Bed coal-fired steam electric plant. The plant will be equipped with limestone injection, dry-lime scrubber, selective non-catalytic reduction with ammonia injection and a baghouse for control of the various emissions. The source will be located in Sevier County, near the town of Sigurd Utah. Sevier County is an attainment area of the National Ambient Air Quality Standards (NAAQS) for all pollutants.

This project is a new major Prevention of Significant Deterioration (PSD) source. Onsite meteorological monitoring, air dispersion modeling, air quality impacts analysis including visibility and PSD class I and II impacts analysis, and a complete top-down Best Available Control Technology (BACT) review were completed and submitted as part of the NOI.

New Source Performance Standards (NSPS) and Maximum Achievable Control Technology (MACT) regulations apply to this source. Title IV of the 1990 Clean Air Act applies to this source. Title V of the 1990 Clean Air Act also applies to this source, with the requirement of submitting a Title V application within one (1) year of beginning operation.

The emissions, in tons per year, will increase as follows: PM₁₀ 177.4, NO_x 1066.1, SO₂ 547.3, CO 1278.6, VOC 53.4, HAPs 16.9.

Newspaper Notice

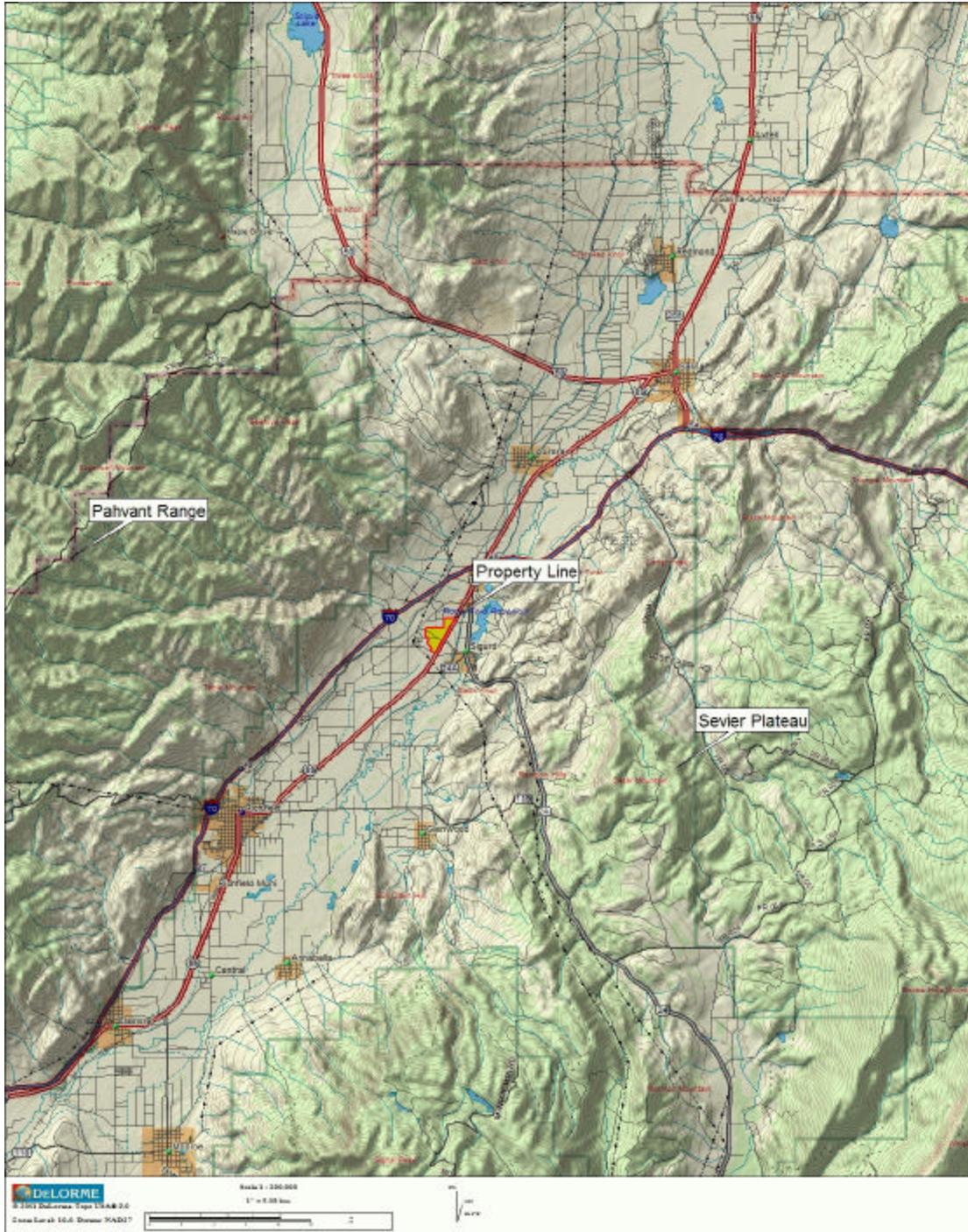
NEVCO Energy Company LLC has submitted a Notice of Intent (NOI) to construct and operate a 270 MW Circulating Fluidized Bed coal-fired steam electric plant. The plant will be equipped with limestone injection, dry-lime scrubber, selective non-catalytic reduction with ammonia injection and a baghouse for control of the various emissions. The source will be located in Sevier County, near the town of Sigurd Utah. Sevier County is an attainment area of the National Ambient Air Quality Standards (NAAQS) for all pollutants.

I. DESCRIPTION OF PROPOSAL

The following sections describe the proposed project location, a description of the site and surrounding terrain, a description of the proposed facility, as well as proposed operating scenarios.

I.1 Facility Location and Description

The Sevier Power Company proposes to build a 270 MW coal-fired power plant utilizing circulating fluidized bed technology near Sigurd, Utah. Sigurd is located in Sevier County, Utah in a northeast-southwest oriented valley. Figure I.1 presents the location of the proposed facility in comparison to major cities nearby. Figure I.2 shows a close-up view of the proposed facility boundary.



I.2 Description of Proposed Facility

The primary components of the proposed SPC Project include a circulating fluidized-bed boiler with a nominal capacity of 270 MW with limestone injection, a dry lime scrubber, selective non-catalytic reduction (SNCR) with ammonia injection, and coal and limestone handling facilities. The CFB boiler will supply superheated steam to the turbine to drive an electrical generator and supply steam through uncontrolled extraction from the turbine. Table I-1 summarizes the principal parameters associated with the design and operation of the facility.

Table I-1
Key Facility Design and Operational Parameters

Nominal Output	270 MW Gross
Boiler Type	Circulating Fluidized Bed
Primary Fuel	Coal
Heat Input (Full Load)	2531.5 mmBtu/hr
Startup Fuel	Natural Gas
Heat Input (Startup)	420 mmBtu/hr
Particulate Control Device	Fabric Filtration
Nitrogen Oxides Control Device	Selective Non-Catalytic Reduction (SNCR)
Carbon Monoxide and Volatile Organic Compound Control Device	Combustion Controls
Sulfur Dioxide Control Device	CFB Boiler/Dry Scrubber

I.3 Facilities

The major plant buildings include the boiler and turbine building. This building is further described in the following paragraphs.

I.3.1 Boiler Building

The boiler building will be open and will house the CFB boiler. The boiler will have an adequate number of platforms to meet operating and maintenance requirements. The combustion air fans and the compressed air system equipment will be located on the ground floor of the boiler building. The limestone storage and fuel storage bays will be located on the front side of the boilers.

I.3.2 Turbine Building

The turbine building will be an enclosed structure consisting of two principal levels: ground and operating floors. Intermediate platforms will be installed to provide the accessibility required for normal plant operation and maintenance. The turbine generator will be supported on a reinforced concrete pedestal located at the operating deck level. A bridge crane will be provided over the operating deck level for turbine generator service. In addition, a large hatchway will be provided in the operating floor with access to the ground floor laydown area. Feedwater heaters and pumps will be located in a bay adjacent to the turbine bay. The building will be made of structural steel, supported on foundations and enclosed with metal siding and a built-up roof.

In addition to the buildings described above, the plant will incorporate several major facilities and structures. These are discussed in further detail in the referenced sections:

Coal material handling and limestone unloading and conveying facilities (see Sections I.5.2.1 and I.5.2.2)
Ash storage and conveying (see Section I.5.2.5)
Lime receiving and handling (see Section I.5.2.3)
Plant stack (see Section I.4.5)
Air-cooled condenser (see Section I.4.4)

The facility will also include an electrical distribution facility, a control room, an administration building and a small water treatment facility. Figure I.3 presents a plot plan of the facility. Descriptions of the major components of the facility are presented in the following subsections.

I.4 Major Power Block Components

The major power block components consist of the CFB boiler, fluidized heat exchangers turbine generator, air-cooled condenser, stack, and start-up burners. These components are described in the following sections.

I.4.1 Circulating Fluidized Bed Combustor

A drum type CFB boiler will be utilized for the SPC Project. Principal components of a CFB boiler include primary and secondary air fans, combustor, cyclone separator, superheater, evaporator, economizer, air heater, and induced draft fan. The boiler will have a total design heat input of 2531.5 mmBtu/hour at maximum load. The components of the CFB boiler are shown in Figure I.4. Figure I.5 presents a process diagram of the CFB boiler, circulating dry scrubber and fabric filter baghouse. Figures I.6 and I.7 show a side and over-view, respectively, of the CFB boiler, dry circulating scrubber and fabric filter baghouse systems.

Low sulfur (0.25-0.9%) coal will be the fuel. A fuel design analysis is presented in Table I-2. Possible sources of coal for the proposed SPC Project will come from the Sufco Mine or other Utah coal sources.

Figure I.3 SPC Project Plot Plan

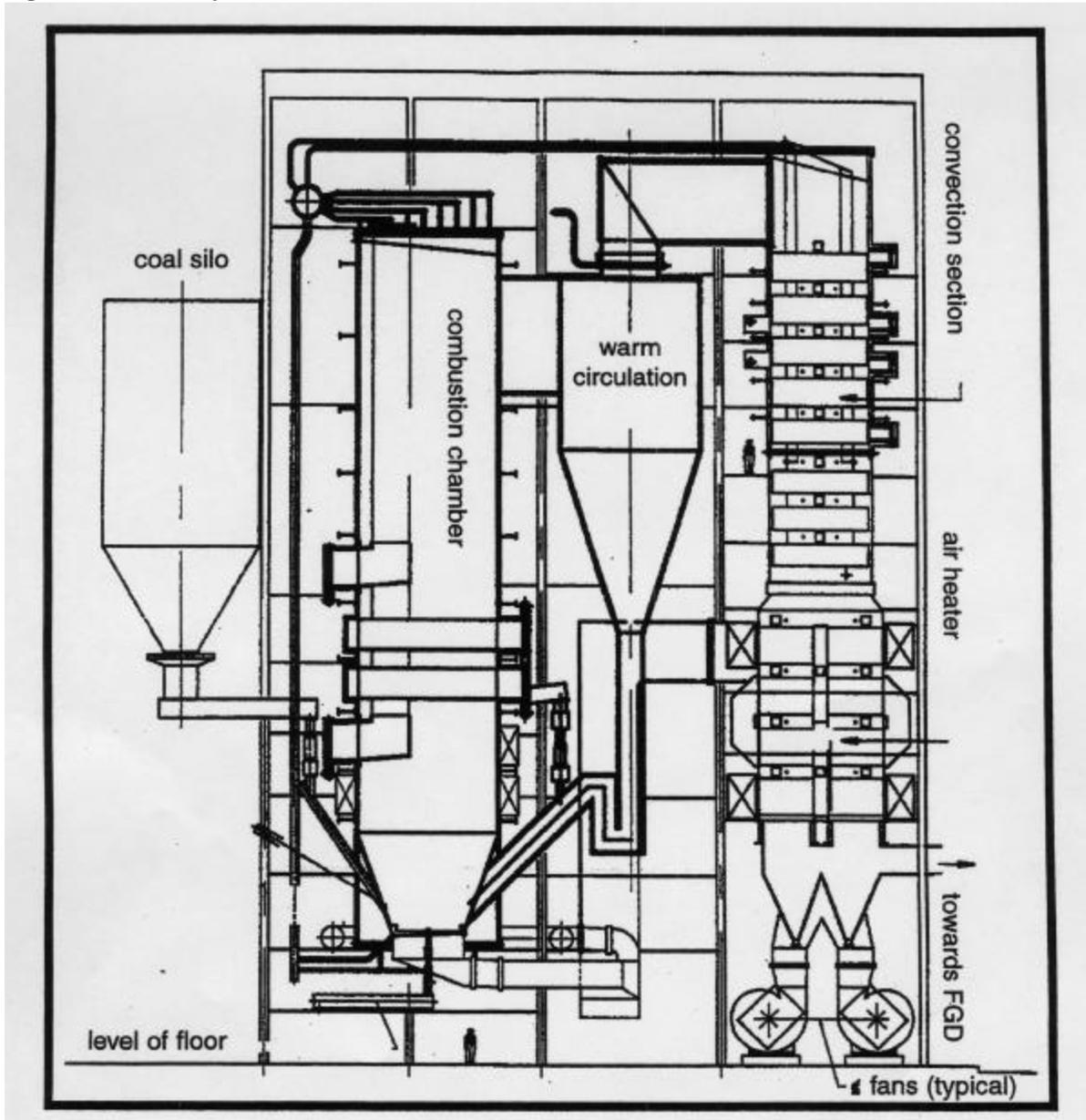
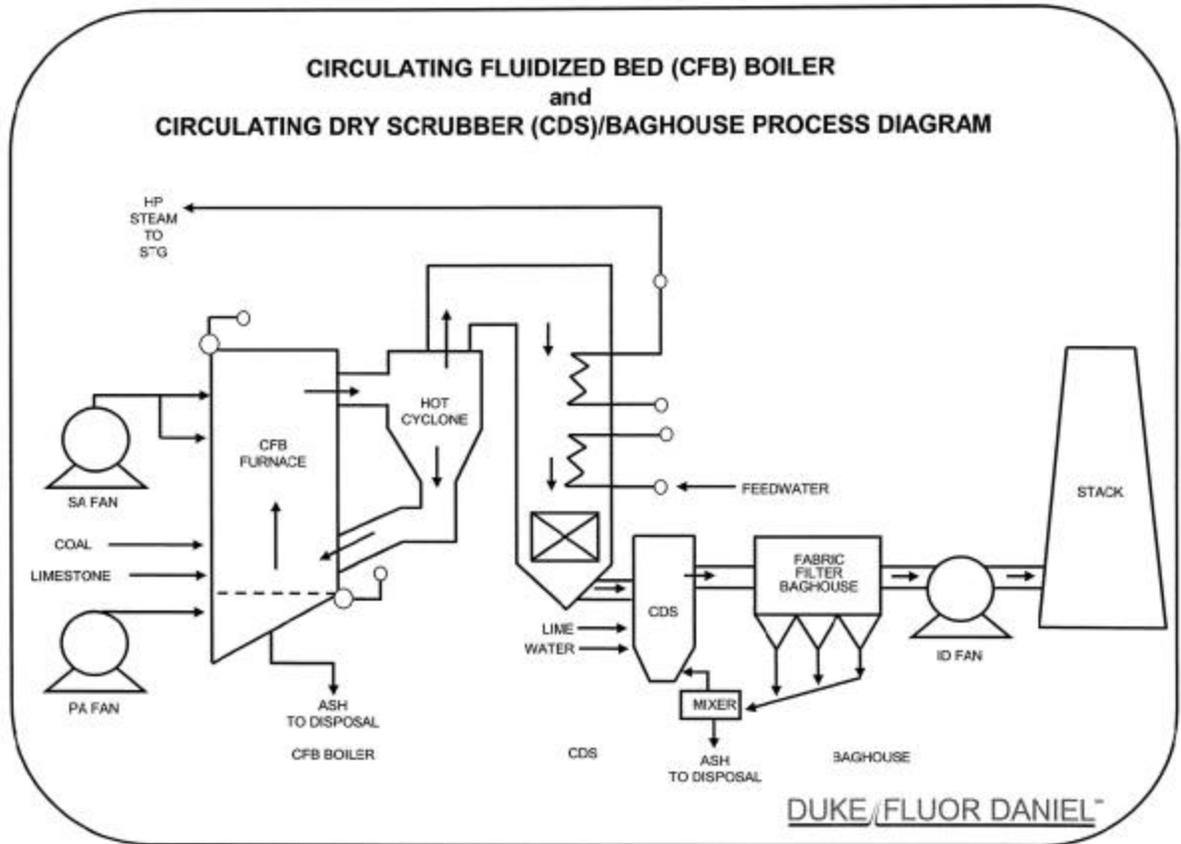


Figure I.4 Components of Circulating Fluidized Bed Boiler



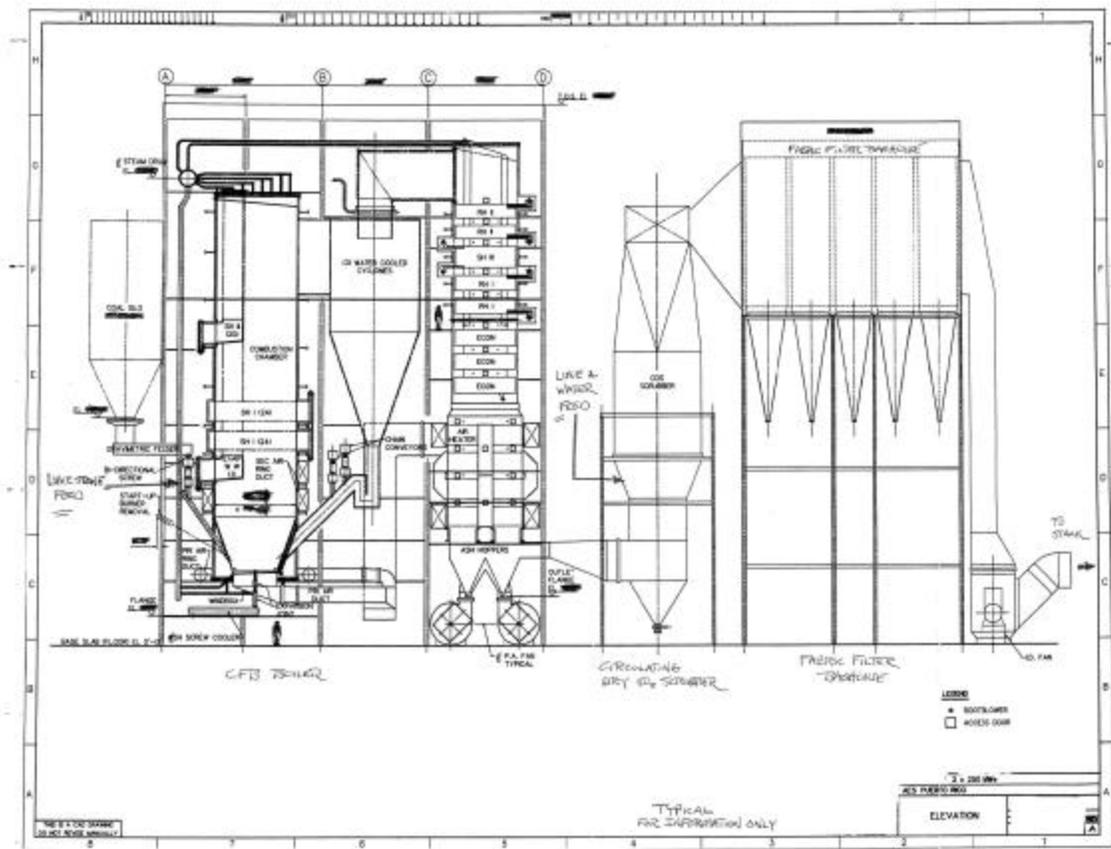


Figure I.5 Process Diagram of CFB Boiler, and Circulating Dry SO₂ Scrubber/ Fabric Filter Baghouse

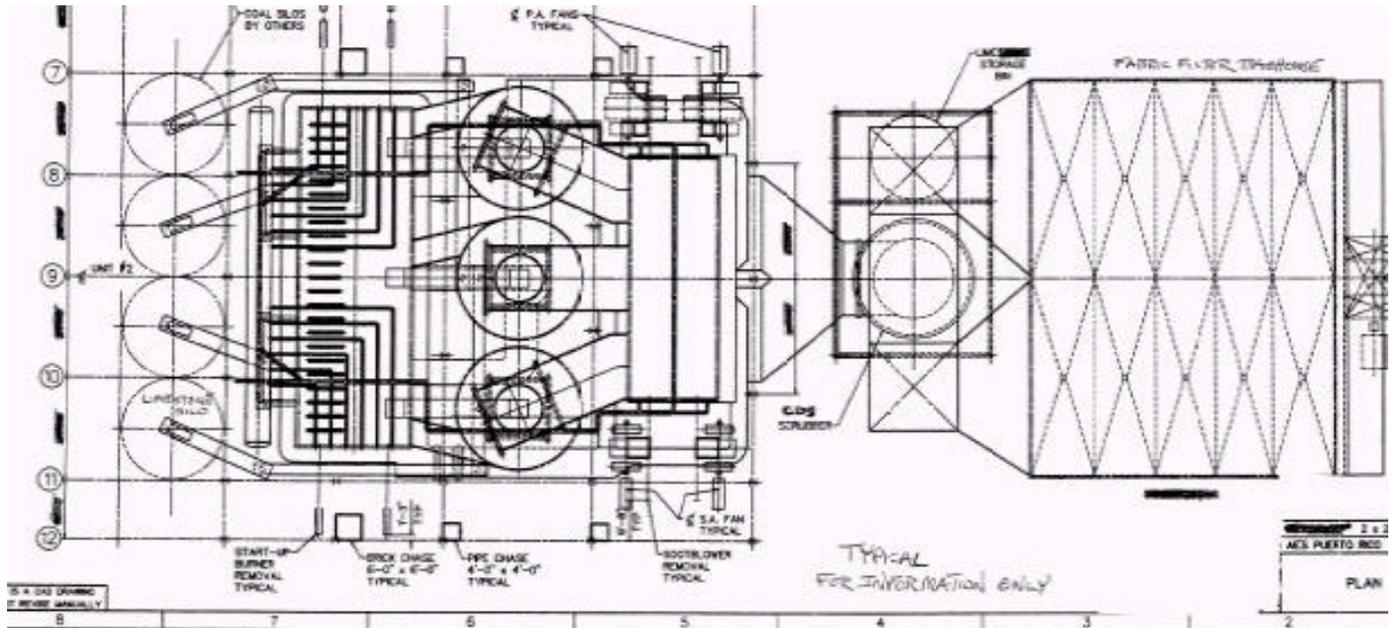


Figure I.7 Top View of CFB Boiler, Dry Circulating SO₂ Scrubber, and Fabric Filter Baghouse

**Table I-2
Design Fuel**

Constituent	Performance Fuel	
	Coal	Range
HHV	11390 Btu/lb	10,200 - 12,000 Btu/lb
Ash	8.30%	6.5 - 12%
Carbon	64.64%	60 - 70%
Hydrogen	4.40%	2 - 6%
Nitrogen	1.11%	0.5 - 1.3%
Sulfur	0.40%	0.25 - 0.9%
Oxygen	11.06%	5 - 15%
Moisture	10.10%	8 - 12%

Combustion in the CFB takes place in a vertical chamber called the combustor. The crushed coal and sorbent are introduced into the combustor, fluidized, and burned at temperatures of approximately 1550 °F. The sorbent is fine-grained limestone, which reacts with the sulfur dioxide released from the burning fuel to form calcium sulfate (gypsum). The bed material in the combustor consists primarily of mineral matter from the fuel, gypsum, and excess calcined lime.

The bed material is fluidized with primary air introduced through a grate at the bottom of the combustor and also by the combustion gases generated. Secondary air is added to the lower section of the combustor to achieve complete and staged combustion.

The suspended solids form a concentration gradient throughout the combustor which decreases gradually toward four outlets on the top. The combustor gas entrains a considerable portion of the solids inventory from the combustor. Solids are separated from the gas in four recycle cyclones and are continuously returned to the bed via recycle loops. A controlled amount of solids from the cyclones is passed through two external fluid bed heat exchangers and returned to the combustor.

Because of the high slip velocity between gas and solids, the solids proceed through the combustor at a much slower velocity than the gas. The longer residence and contact times, coupled with the small particle sizes and high heat and mass transfer rates achieved, result in a high combustion efficiency. These conditions allow both the complete combustion of the limestone and the subsequent capture of the SO₂ at very low calcium to sulfur molar ratios.

Combustion air is fed to the combustor at two levels. Roughly fifty percent of the combustion air is introduced as primary or fluidizing air through the bottom grate, and the balance is admitted as secondary air through multiple ports in the side walls. Thus, combustion takes place in two zones: a primary reducing zone in the lower section of the combustor followed by an appropriately adjusted excess air oxidizing zone in the upper section. This staged combustion, at controlled low temperatures, along with the injection of ammonia into the recycle cyclone outlets, effectively controls NO_x formation and provides conditions to most efficiently capture SO_2 at low calcium to sulfur molar ratios.

The recycle cyclones remove a major portion of the hot ash particles from the flue gas stream. This hot ash settles into the siphon seals. A fluidizing air blower keeps the ash fluid in the siphon seals and fluidized bed heat exchangers (FBHE) and allows it to be metered through the ash control valves (ACV) into the FBHE or to be returned to the combustion chamber.

In the FBHEs the ash is cooled by transferring heat to evaporation sections, finishing superheater sections, and finishing reheater section of the steam generator. The fluidizing air blower keeps the ash fluid while it cools. The ash is subsequently returned to the combustion chamber.

Ash is continuously withdrawn from the combustion chamber with water-cooled screw ash coolers. The ash is then transferred from the screw ash coolers to the rest of the ash system.

Heat from steam generation is removed from the system in the following ways:

In the primary loop, where heat is removed from the solids circulating in the CFB system, heat removal is achieved by the heat-absorbing surface in the water walls of the combustor and heat-absorbing surface located in the fluid bed heat exchangers.

The convective pass is where heat is removed from the flue gas exiting the recycle cyclones. Heat removal is achieved by superheater, reheater, and economizer surfaces.

Relatively clean gases from the recycle cyclones enter the convective pass of the steam generator where they pass over the superheater, reheater, and economizer elements. After the convective pass, the gases are further cooled in an air heater.

From the air heater, the flue gas continues to the baghouse filter for removal of residual particulate and then to the induced draft (ID) fans in the stack.

I.4.2 Fluidized Bed Heat Exchanger

The fluidized bed heat exchangers (FBHE) are a key element of the CFB system. They provide a heat transfer surface external to the harsh environment of the combustion chamber. A portion of the circulating solids is fed to the FBHE where sensible heat is transferred to a steam/water system. Since the feed rate of solids is controlled, optimum combustor conditions can be maintained, irrespective of fuel type or load.

The FBHE operate in the conventional bubbling bed mode. Heat is recovered in chambers that are separated by water wall weirs. Each chamber contains a fluidizing grid and immersed tube bundles. The solid extraction valves control feed rate to the unit. The solids are fluidized in each chamber and cooled by the tube

bundles, water walls, and fluidizing air. The solids discharge directly into the combustor.

The fluidizing velocity is low so solids density and heat transfer coefficients are high. This characteristic combines with the fine particle size of the circulating solids to minimize corrosion. The carbon content of this material is only 1 to 2%. Consequently, there is no combustion in the FBHE. As a result, corrosion is avoided because the tubes are not exposed to a reducing atmosphere.

Two fluid bed heat exchangers are provided for the combustor. The front FBHE contains two finishing superheat and one evaporative components, and the back FBHE contains one finishing reheat and two evaporative compartments. In the front FBHE, solids flow from the first and third siphon seal pots into two separate finishing superheater compartments in parallel. From these compartments, the solids flow into one joint evaporative compartment. Then the solids return to the combustor at approximately 1200 °F. In the back FBHE, solids flow in two distinct flow paths. Solids from the second siphon seal pot enter the evaporative compartments. From there the solids are returned to the combustor at approximately 1800 °F. Solids from the fourth siphon seal follow a different path. They enter the finishing reheat compartment. From there the solids are returned to the combustor at approximately 1250 °F.

Both FBHEs are of water wall construction to provide additional evaporative duty.

During operation, the combustion temperature is controlled by the flow rate of solids to the FBHEs. If a change in fuel or load results in a change in combustion temperature, the solids flow to the FBHEs is modulated accordingly.

A FBHE is an important part of the CFB system and it serves two main purposes, which are:

It provides for a significant portion of the total heat transfer duty, and
It provides a close control of the combustion temperature during part load operation.

I.4.3 Turbine Generator

The turbine generator will use 2400 psig/1000 °F throttle steam. An integral lubrication and hydraulic control system will be provided with the turbine and will include a lube oil reservoir, lube oil coolers, and AC operated lube oil pumps with DC backup.

The generator will be a two-pole, synchronous, 3,600 rpm, hydrogen- or air-cooled unit and will include necessary grounding, instrument transformers, surge protection, and excitation equipment.

The generator lube oil system will be integral with the turbine system. Stop valves will be provided to isolate the turbine from the boiler during startup and also emergency overspeed trip following loss of electrical load.

I.4.4 Air Cooled Condenser

The air-cooled condenser system cools and condenses turbine exhaust steam and returns condensate flow to a hotwell holding tank. Heat is rejected in a mechanical draft air-cooled surface condenser.

The air cooled condenser system include the following:

- ?? Fin tube bundles with integral condensate/crossover headers,
- ?? A-frame support structure for tube bundles, partition walls and doors,
- ?? Fans, motors, gear boxes, couplings, and fan deck,
- ?? Condenser support structure, including stairway, walkway, and hand rails,
- ?? Condensate collection tank (hotwell) and makeup water vacuum deaerator,
- ?? Piping and valves, and
- ?? Instruments and controls.

The condenser maintains the turbine backpressure. The duty of the condenser is based on the turbine exhaust and the enthalpies given by the turbine-generator valves wide open (VWO) condition heat balance at the rated condenser backpressure. Also included in the duty is the energy from the gland steam sealing system and the feedwater heater drains. The required air-cooled condenser airflow is determined using the VMO duty and the specified temperature range. Two-speed motors will drive the condenser fans. Each fan gear reducer has a low oil level switch.

I.4.5 Stack

Flue gas will be exhausted from the boiler/scrubber train by induced draft fans to a 450 feet above ground good engineering stack. (Refer to Section 6.1.7 for the basis for this height). The stack will be equipped with aircraft warning devices in accordance with Federal Aviation Administration (FAA) requirements. Ports will be provided to accommodate flue gas sampling equipment.

I.4.6 Start-Up Burners

Start-up burners are used for preheating the bed up to coal ignition temperature. The start-up burners, fired on natural gas, operate with air supplied from the secondary fan and are retracted when the temperature in the combustor reaches approximately 1300 °F. Two starts per year are proposed. Each start will require operating approximately 7 hours on natural gas. Heat input at start-up is estimated to be 420 mmBtu/hr.

I.5 Major Plant Systems

There are two major steam systems at the proposed plant. These systems are the main steam system and the extraction steam and heater drain system.

I.5.1 Steam System

The main steam system is designed to supply superheated steam to the turbine. The piping system is designed for a steam flow corresponding to the maximum load. Steam conditions at the turbine inlet will be 2400 psia/1000 °F. Control valves will regulate steam flow to the turbine.

Startup vents and drains will be provided to facilitate warm-up of the main steam line prior to use.

The extraction steam system is designed to heat feedwater. The extraction steam system also provides steam for the auxiliary steam system and for support process steam.

The feedwater heater arrangement will consist of two high-pressure heaters with de-superheating and internal drain coolers, one direct contact de-aerating heater, and three low-pressure heaters.

I.5.2 Material Handling Operations

Coal, lime, and limestone handling will be conducted for the SPC Project. These handling operations are described in the following sections.

I.5.2.1 Coal Material Handling

It is estimated that 75 coal trucks with pups will arrive daily at the site. The coal will be transported by conveyor to the active 30-day coal storage pile. The coal feed system from the coal pile empties into five (5) coal silos, each with an approximate capacity of 665 tons. Each coal silo has a hopper and isolation valve that discharges the coal into the gravimetric feeder. The fuel can be extracted from the silos at variable rates as required by the operation of the boilers.

Three (3) coal silo isolating valves are furnished to isolate each fuel train from each coal silo. The twin knife gates utilize a rack and pinion drive arrangement to allow closure against a full silo. Each of the two opposing gates in each valve has a hand wheel activator.

The coal silo hoppers discharge the solid fuel into the three (3) enclosed pressurized gravimetric feeders. One feeder is provided for each of the eight fuel feed trains. The feeders are furnished with a variable speed DC drive and controller that regulates the fuel feed to the combustor by varying the belt linear speed.

The feeders will be provided with drag chain scavengers driven with separate AC motors to recover any fuel spillage at the bottom of the feeder housing.

Other features furnished with the feeders include: access doors at each end of the feeders, glass observation ports, internal lights, provisions for coal sampling, and switches for sensing.

Three (3) pneumatically operated slide gate valves (one per train) are furnished to isolate each train from the siphon seal solid return lines for maintenance shutdowns. The valve gate is provided with a dual cylinder actuator and a rack and pinion equalizer. The valve packing and actuator are provided with an air purged bonnet enclosure to prevent gas leakage.

As a safety feature, four fail-safe packages (one per valve) are supplied to automatically shutdown the valve in the event of a power outage. Each fail-safe package includes an air accumulator, air filter/regulator/lubricator, open/close limit switches, pressure switches, air feed control valve, and solenoid and check valves.

I.5.2.2 Limestone Material Handling

It is estimated that 3 limestone trucks plus pups will arrive daily at the site with prepared (crushed and dried) limestone. The trucks will dump the limestone into the unloading hopper and it will be transported by conveyor to a prepared limestone storage area. From the prepared limestone storage area, a limestone transport blower provides the necessary air for transporting the prepared limestone to the prepared limestone silos. Each silo will have an approximate capacity of 325 tons.

A pneumatic transport system provides prepared limestone to the prepared limestone silo. From the silo, prepared limestone is discharged to the limestone injection system.

One vent filter is provided on the top of the prepared limestone silo. The vent filters are pulse jet type, which will be supplied with necessary valves and timers for sequential bag cleaning.

There is one prepared limestone silo vent fan for the silo which discharges air vented from the silo through the silo vent filter to the atmosphere.

Two (2) parallel limestone injection systems are provided for the combustion unit. The limestone from the limestone silo is injected into the combustor at multiple points to control SO₂ emissions.

Prepared limestone from the limestone silo flows through the limestone silo outlet gate to the rotary feeder. The rotary feeder acts as a seal between the pressurized pneumatic injection system and the limestone silo and it also meters the limestone into the pneumatic system. A positive displacement blower provides the conveying air, which transports the limestone/air mixture to the flow proportioner. The flow proportioner divides the limestone/air mixture into two streams that are then injected into the combustor via injection nozzles. A knife gate isolation valve is provided at each nozzle, to isolate the injection system from the combustor for maintenance purposes.

I.5.2.3 Lime Receiving and Handling

For the dry scrubbing, lime will be injected directly into the flue gas to remove SO₂ and hydrogen chloride (HCl). The lime handling system will include equipment for storing lime delivered to the site by truck and discharging lime to the circulating dry scrubber reactant preparation system.

Trucks delivering lime to the site will be equipped with a pneumatic transport to convey lime to the storage silos. Assuming seven days of storage, one 80-ton silo will be installed at the facility. A baghouse design vent filter and vent fan located on the silo roof will filter air from the trucks unloading transport air and displaced air from the silo.

Lime is discharged from the silo at a controlled rate to the circulating dry scrubber reactant preparation system. The lime feed rate is expected to be approximately 1000 pounds per hour for the boiler and will be automatically adjusted in response to the SO₂ level in the stack and to optimize the amount of SO₂ removal.

I.5.2.4 Dust Control Systems

Dust control and collection systems will be installed at all material transfer points. The dust collection system will be either induced-draft filter bag units or insertible cartridge-type filters, designed to be inserted directly into a conveyor head chute or loading skirt, as appropriate.

I.5.2.5 Ash Handling System

The ash by-product generated by the facility is stored in concrete or carbon steel silos constructed with underneath truck loading capability. The ash by-product will be transported daily off-site to an approved ash disposal site in covered trailers that deliver coal to the plant. It is estimated that 5 tons of fly ash and 25 tons of bed ash per hour will be generated from the boiler.

The loading system will have the capability to load dry ash into a fully enclosed trailer. Each ash silo has a

telescopic truck-loading spout. The spout is equipped with a dust removal fan that maintains the spout at a negative pressure to recover dust generated during the truck loading process. This dust removal fan discharge is routed back to the ash silo.

Two ash storage silos are proposed to be located at the facility: one for bed ash and one for fly ash. Two full-capacity mechanical exhausters will be provided for conveying ash to the silos.

I.5.3 Electrical System

Electrical output from the combustors and the steam turbine generator will be transmitted to a 600KV switchyard and interconnected to the Sigurd substation.

I.5.4 Plant Control and Monitoring System

The control system will be a microprocessor-based distributed control and monitoring system (DCS). It will interface with the process input and outputs and communicate via a communications highway to the operator systems located in the main control room.

The DCS will contain two major systems: the plant control system and the data acquisition system (DAS).

The plant control and DAS will be integrated into one system to provide power control action and plant monitoring capability for startup, transient, and steady state operation and safe shutdown.

The main control room equipment will include:

- ?? main control console,
- ?? engineering console with CRT and keyboard, printer, and disk drives,
- ?? auxiliary control panels for stack monitoring, ash handling, and fire protection monitoring,
- ?? alarm logger and printer,
- ?? electrical control panel, and
- ?? historical storage and retrieval unit.

Local control panels or stations will be furnished where operator attention is required only to set up a system for operation or where the equipment to be operated requires only intermittent attention during plant operation.

I.5.5 Diesel Emergency Generator

A diesel-fired emergency generator, with a rating of 750 HP, is proposed for this project. The operating hours for the generator will be limited to 120 hours per year. A 1,200 gallon diesel storage tank is also proposed for this project.

I.5.6 Diesel Fire Pump

The proposed fire pump will be diesel-fired with a rating of 750 HP. The fire pump will be limited to 120 hours of operation annually. A 1,800 gallon diesel storage tank is also proposed for use by the fire pump.

I.5.7 Water Treatment System

The SPC Project has acquired enough underground water rights to easily supply the facilities water requirements. It is estimated that 155 acre-feet of water is needed annually for the project. The plant will consume approximately 87 gallons of water per minute. The water will be cleaned on-site at the water treatment facility. This system will be a zero discharge and zero emission system.

I.6 Air Emission Control

In a CFB boiler, solid particles of fuel and inert materials are suspended and burned in an air stream that creates a highly agitated mass. Enhanced combustion and heat transfer at lower temperatures results from this fluidization. The specific characteristics of this process are dependant upon bed temperature, size of the particles, and the fluidization velocity. Limestone, which is fed into the bed with the coal, forms lime upon calcination which reacts with the sulfur oxides from the sulfur-containing fuels. These chemical reactions form waste products of calcium sulfite and calcium sulfate. Ash and unreacted lime and limestone are removed as particulate matter using fabric filters.

A circulating dry scrubber will be used in addition to limestone injections to lower SO₂, H₂SO₄, and fluoride emissions. This process uses a gas-phase reaction between SO₂, H₂SO₄ and fluorides with hydrated lime in a fluid bed reactor placed downstream of the CFB boiler upstream of the fabric filters. Gas enters the scrubber vessel at the bottom and flows vertically upward through the venturi section. Ash is recirculated through the scrubber to optimize fresh lime consumption.

Fluidized bed consumption allows the heat release in the combustion chamber to occur at a lower temperature (1450-1650 °F) while maintaining efficient combustion. Temperatures below ash-softening temperatures eliminate the problems of slagging and fouling and also result in lower thermal NO_x emissions levels.

NO_x will be removed from the flue gas with a SNCR system. The system will be placed downstream of the combustion chamber at the inlet to the hot cyclone. Two 15,000 gallon aqueous ammonia tanks will be associated with the SNCR system.

I.7 IGCC as Alternative Project

Integrated gasification coal combustion (IGCC) was evaluated as an alternative production process for generating electricity from coal. Integrated gasification coal combustion is a two stage process. In the first stage, coal or other fuel are first gasified to produce a synthetic gaseous fuel. In the second stage, this gaseous fuel is then used to fire combined cycle turbines to generate electricity. For the Sevier Power Company Project, IGCC was not chosen due to the higher costs.

II. EMISSION SUMMARY

The emissions from Sevier Power Company will be as follows:

<u>Pollutant</u>	<u>Actual Emissions tons/year</u>	<u>Requested PTE Increase tons/year</u>	<u>Actual to Potential Increase tons/year</u>	<u>Total PTE Emissions tons/year</u>
PM ₁₀	0.00	177.4	177.4	177.4
SO ₂	0.00	0.00	547.3	547.3
NO _x	0.00	1066.6	1066.6	1066.6
CO	0.00	1278.6	1278.6	1278.6
VOC	0.00	53.4	53.4	53.4
Pb	0.00	0.1	0.1	0.1
PM	0.00	177.4	177.4	177.4
Fl	0.00	2.1	2.1	2.1
HF	0.00	5.3	5.3	5.3
H ₂ SO ₄ mist	0.00	25.5	25.5	25.5
HAPs				
HCL	0.00	16.9	16.9	16.9
Total HAPs	0.00	24.7	24.7	24.7

547.3

Pollutant	Current PTE Tons/year	Actual Emissions Tons/year	Requested PTE Increase Tons/year	Actual to Potential Increase Tons/year	New PTE Tons/year
PM ₁₀	0	0	177.4	177.4	177.4
SO ₂	0	0	547.3	547.3	547.3
NO _x	0	0	1066.6	1066.6	1066.6
CO	0	0	1278.6	1278.6	1278.6
VOC	0	0	53.4	53.4	53.4
Total HAPs	0	0	24.7	24.7	24.7
HCl	0	0	16.9	16.9	16.9

II.1 Modeling Analysis Review for the Nevco Energy – Sevier Power Plant

II.1.1 Objective

Nevco Energy (Applicant) has submitted a Notice of Intent (NOI) for the proposed construction of a power plant in Sigurd, Utah. The facility would consist of a coal-fired fluidized-bed boiler/steam turbine generator with a gross capacity of 270 MW. The proposed increase in emissions associated with the construction of this unit constitutes a new major source subject to Prevention of Significant Deterioration (PSD) permitting rules. The rules require the Applicant to include an air quality impact analysis (AQIA) of the proposed project impact as part of a complete NOI.

This report prepared by the Staff of the Technical Analysis Section (TAS) contains a review of the Applicant's AQIA including the methodology, data sources, assumptions and modeling results used to determine compliance with State and Federal air quality standards. The NOI document reviewed and referenced in this report is the "Prevention of Significant Deterioration Permit Application for Sevier Power Company Proposed 270 MW Coal-Fired Power Plant, Volumes 1 and 2," prepared by Meteorological Solutions, Incorporated, of Salt Lake City, Utah. It was submitted on behalf of the Applicant and received by the Division on September 10, 2003.

II.1.2 Applicability

The proposed increases in emissions of PM₁₀, NO_x, CO, SO₂, VOC, and two HAPs exceeds the emission thresholds outline in R307-406-5, R307-410-3 and R307-410-4. Therefore, an AQIA consistent with the requirements of R307-405-6, R307-406-2, R307-410-2, and R307-410-4 was submitted as part of the Applicant's NOI. The results of the AQIA are required to demonstrate the proposed project's impact on state and federal air quality standards, acceptable levels of impact, and action triggering thresholds referenced or listed in R307-401-6(2), R307-401-6(3), R307-403-3(1), R307-403-5(1)(a), R307-405-4(1), R307-405-6(2), R307-405-6(6), and R307-410-4(1)(d). Annual emission estimates in tons per year (TPY) for the proposed project are listed in Table II-1 below.

Table II-1: Proposed New Criteria Emissions from the Sevier Power Plant

Pollutant	Proposed Plant Total (TPY)
NO _x	1066.6
SO ₂	547.3
PM ₁₀	177.4
CO	1278.6
VOC	53.4
Lead	0.12
Beryllium	0.0098
Hydrogen Chloride	25.6

II.1.3 Modeling Methodology – Near-Field Analysis

A. Pre-Construction Monitoring Analysis

R307-405(6)(2)(a)(i)(B) requires the Applicant to perform a pre-construction modeling analysis to determine if the extent of the source's impact is significant enough to warrant an accurate measurement of the normal ambient background concentration levels, for inclusion in the National Ambient Air Quality Standards (NAAQS) analysis. This analysis is required for all pollutants emitted in a significant quantity (i.e., NO_x, SO₂, PM₁₀, and CO).

B. NAAQS Analysis

R307-401-6(2) requires the Division to determine through planned review that the proposed project will comply with NAAQS prior to the issuance of an Approval Order (AO). R307-410-2 and 3 provides further

clarification by assigning the burden for conducting AQIAs, and establishes the U S Environmental Protection Agency (US EPA) – Guideline on Air Quality Models as a formal basis for defining the scope of the analysis, as well as the model’s construction. R307-405(6)(2)(a)(i)(B) requires the Applicant to perform a NAAQS analysis for all pollutants emitted in a significant quantity (i.e., NO₂, SO₂, PM₁₀, and CO). This analysis is to include all emissions at the proposed site under normal operating conditions using maximum anticipated short-term and annual release rates, the ambient background concentration of the atmosphere, and if applicable, any contribution from other sources of the pollutant in the area of study.

C. PSD Class II Increment Consumption Analysis

R307-401-6(2) also requires the Division to determine through planned review that the proposed project will comply with PSD increments prior to the issuance of an Approval Order (AO). In accordance with R307-410-1 and 2, and R307-405(6)(2)(a)(i)(B), the Applicant is required to perform a PSD Class II increment consumption analysis for NO₂, SO₂, and PM₁₀, in order to quantify any degradation in air quality in the area surrounding the site since the major source baseline dates. The major source baseline dates for this analysis are April 21, 1988, for NO₂ and August 17, 1979, for SO₂ and PM₁₀. This analysis is to include all emissions of the three pollutants at the proposed site under normal operating conditions using maximum anticipated short-term and annual release rates. If applicable, contributions since the baseline date associated with growth and other increment consuming sources should also be evaluated.

D. Hazardous Air Pollutant (HAP) Analysis

R307-410-4 requires the Applicant to perform a HAPs analysis for any pollutant emitted above a pollutant specific emission threshold value. Based on emission projections listed in the NOI, the Applicant is required to perform an analysis for arsenic, beryllium, cadmium, cobalt, selenium, hydrogen fluoride and hydrogen chloride. This analysis is to include all emissions of the seven pollutants at the proposed site under normal operating conditions using maximum anticipated one-hour release rates.

E. General Modeling Inputs and Assumptions

1. Topography/Terrain

The Plant is at an elevation of 5220 feet with distant terrain features that have little effect on concentration predictions.

- a. Zone: 12
- b. Approximate Location: UTM (NAD27): 414870 meters East, 4299941 meters North

2. Model and Options

The US EPA Industrial Source Complex Short Term - Version 3 (ISCST3) model was used by the Applicant to predict air pollutant concentrations in the near field (within 50 kilometers of the source). In quantifying concentrations, the regulatory default options were selected by the Applicant.

3. Urban or Rural Area Designation

After a review of the appropriate 7.5-minute quadrangles, it was concluded that the area is “rural” for air

modeling purposes.

4. Ambient Air

It was determined that the Plant boundary used in the AQIA meets the State's definition of an ambient air boundary.

5. Building Downwash

The Applicant used the US EPA - Building Profile Input Program (BPIP) to determine Good Engineering Practice (GEP) stack heights and cross-sectional building dimensions for input into the ISCST3 model. Stack parameters and building dimensions were input into the BPIP. It was assumed that ground level elevations for the stacks and buildings were the same. The output from BPIP showed all stacks to be less than their GEP formula stack height; thereby, required a wake effect evaluation.

6. Receptor and Terrain Elevations

The near-field modeling domain (53 km x 53 km) used by the Applicant consisted of 38,750 receptors including property boundary receptors. The modeling domain has simple and complex terrain features in the near field. Therefore, receptor points representing actual terrain elevations from the area were used in the analysis.

F. Pre-Construction Monitoring Data

1. Onsite Meteorological Data

As part of a complete NOI, the Guideline on Air Quality Models require PSD applicants to collect one year of onsite meteorological data for use in the AQIA. Onsite data collection was performed using a 100-meter tower, commencing on August 6, 2001, and running through August 6, 2002. Parameters collected onsite included wind speed and direction (10 and 100 meter), vertical wind speed (10 and 100 meters), temperature (2, 10, and 100 meters), barometric pressure, solar radiation, net radiation, precipitation, and relative humidity. National Weather Service (NWS) upper air data collected at the Salt Lake City International Airport for the same period was combined with the onsite surface data using the US EPA – Meteorological Preprocessor for Regulatory Models (Version 99349). Two meteorological data sets were compiled from the data. The first data set incorporated the wind speed and direction data collected at 10 meters. This data set was used to simulate the dispersion of low-level emission sources at the site. The second data set incorporated the wind speed and direction data collected at 100 meters. It was used to simulate the dispersion of emissions from the plant's 141-meter main stack, and other contributing sources having tall stacks capable of long-range transport.

2. Ambient Pollutant Data

A preliminary modeling analysis was conducted to determine the necessity for pre-construction ambient pollutant monitoring. The modeling results were compared against R307-405 (6) – *Monitoring Requirement Exemptions*. The meteorological data set used in the preliminary modeling analysis was derived from five years of hourly Salt Lake City NWS data.

The results of the analysis indicated that SO₂ concentrations exceeded the monitoring trigger levels and PM₁₀ concentrations approached the monitoring trigger levels. As a precaution, the Applicant performed one year of onsite PM₁₀ monitoring to quantify ambient concentrations around the proposed site. For SO₂, the Applicant, with UDAQ's concurrence, exercised the monitoring exemption cover under R307-410-6(b)(ii). One year of rural SO₂ monitoring data collected at a site 50 miles northwest of the proposed Sigurd site during 2001-2002 reported a high second-highest 24-hour average concentration of 9 µg/m³ for the period. The exemption threshold for pre-construction monitoring is 13 µg/m³. Later results of a post-meteorological monitoring analysis using the Applicant's onsite meteorological data indicated that the 24-hour average SO₂ monitoring trigger level was not exceeded.

G. Ambient Background Concentrations

Sevier County is in attainment for all pollutants. Background concentrations of SO₂, NO₂, and CO were obtained from the UDAQ's databases for ambient pollutant monitoring. From the onsite PM₁₀ monitoring, the background 24-hour PM₁₀ concentration was calculated based on the second highest 24-hour recorded PM₁₀ concentration collected at the monitoring station. The background values used in the NAAQS analyses are presented in Table II-2.

Table II-2: Background Concentration for the Sevier Power Analysis

Pollutant	Averaging Period	Background Concentration (in µg/m ³)
PM ₁₀	24-Hour	78
	Annual	29.2
SO ₂	3-Hour	20
	24-Hour	10
	Annual	5
NO ₂	Annual	10
CO	1-Hour	1150
	8-Hour	1150

H. Emission Rates and Release Parameters

The criteria pollutant emission estimates and source parameters including UTM coordinates, stack base elevations, and source release parameters for each point and fugitive source are presented in Tables 6-2 and 6-3 of the NOI. "Worst-case" hourly and annual SO₂ and particulate emissions were determined based on coal sulfur content analyses supplied by various Utah mines. Short-term maximum emission rates for SO₂ and PM₁₀ were based on the highest reported seven-day rolling average sulfur content of 0.9%. Annual emission rates for SO₂ and PM₁₀ were based on a worst-case annual average sulfur content of 0.7%.

II.1.4 Modeling Methodology – Far-Field Analysis

A. Required Analysis

1. PSD Class I Increment Consumption Analysis

In accordance with R307-410-1 and 2 and R307-405(6)(2)(a)(i)(B), the Applicant is required to perform a PSD Class I increment consumption analysis for NO₂, SO₂, and PM₁₀, in order to quantify any degradation in air quality in the Class I areas since the major source baseline dates. This analysis is to include all emissions of the three pollutants at the proposed site under normal operating conditions with maximum anticipated short-term and annual release rates, and any contribution associated with growth and other increment consuming sources affecting the area of study.

2. Visibility – Plume Blight and Regional Haze

Under R307-405(6)(2)(a)(i)(B) and R307-406-2, the Applicant is required to perform an analysis to address impacts from the proposed project on visibility in the Class I areas of concern.

A plume blight analysis is required to determine if plumes emanating from the proposed project would be visible inside the Class I area. This analysis is to include all emissions of NO₂, SO₂, SO₄, and PM₁₀ at the proposed site under normal operating conditions with maximum anticipated 24-hour average emission rates.

A regional haze analysis is required to determine if plumes emanating from the proposed project would reduce the visual range of an observer inside the Class I area. This analysis is to include all emissions of SO₂, SO₄, NO₂, and PM₁₀ at the proposed site under normal operating conditions with maximum anticipated 24-hour emission rates.

3. Air Quality Related Values - Soils and Vegetation Analysis

R307-405(6)(2)(a)(i)(D) requires the Applicant to perform a soils and vegetation analysis. The analysis will seek to quantify deposition rates for nitrate and sulfate in the Class I area. This analysis is to include all emissions of NO₂ and SO₂ at the proposed site under normal operating conditions with maximum anticipated annual emission rates.

4. Non-attainment Boundary Impact Analysis

R307-403-5 requires the Applicant to perform an analysis to address the proposed source's impact on the Utah County PM₁₀ non-attainment boundary. The analysis will seek to quantify the combined impact of PM₁₀ and two secondary pollutants, in their gaseous form, in the non-attainment area. This analysis is to include all emissions of SO₂, NO₂, and PM₁₀ at the proposed site under normal operating conditions with maximum anticipated 24-hour emission rates.

B. General Assumptions

1. Model and Options

The US EPA - CALPUFF (Version 5.5) model was used by the Applicant to predict air pollutant concentrations in the far field (long range transport conditions beyond 50 kilometers from the source). The CALPUFF model options and switch setting used in the analysis are listed in detail in Tables 7-4 and 7-7 of the NOI.

2. Receptor and Terrain Elevations

The far-field modeling domain (700 km x 360 km) used by the Applicant consisted of 1421 receptors in six Class I areas. As per a request by the National Park Service, two kilometer by two kilometer (2 km X 2 km) receptor grid spacing was used for the five National Parks in southern Utah. After discussion with the Forest Service, receptor locations for the Weminuche Wilderness Area were placed at the area's boundary. Receptor terrain elevations were determined from 30-meter DEM data. The terrain elevation data was obtained from the United States Geological Survey's (USGS) Digital Elevation Model (DEM) in NAD 27 format. The terrain data consisted of 1-degree quadrangles with a scale of 1:250,000 and a horizontal resolution of 90-meters. The 7.5-minute maps with a horizontal resolution of 30 meters were used for receptor height determination. The grid extended over the entire study area, and the grid spacing was set to 2 km to adequately resolve important terrain features.

3. Meteorology

The CALPUFF model uses the CALMET pre-processor to prepare three-dimensional, hourly meteorological fields for CALPUFF. Three-dimensional time-varying fields of meteorological conditions were developed using hourly surface observations obtained from the NWS Salt Lake City, Utah and Grand Junction, Colorado offices and other surface stations found in the Mesowest Network. The hourly surface observations included: wind speed, wind direction, temperature, cloud cover, ceiling height, surface pressure, relative humidity, and precipitation. Mesowest stations that collected meteorological data within the modeling domain were reviewed for data quality, representative location, and period of record coincident with the MM5 data.

Upper air data required by CALMET include profiles of wind speed, wind direction, temperature, pressure, and elevation. Twice-daily upper air sounding data, obtained from the National Climatic Data Center for Salt Lake City, Utah and Grand Junction, Colorado for the period January 1999 through January 2000 were used in the analysis.

One year of Rapid Update Cycle (RUC2) data converted onto a 30 km Lambert Conformal grid and written into the MM5.dat format for the period January 26, 1999, through January 26, 2000, were input to the CALMET model. The data included 17 vertical levels extending to 450 millibars. The MM5 wind data was checked at various levels for continuity. MM5 temperature data, surface meteorological data, stability class, leaf area index, land use category, elevation and precipitation rates were also checked using the same software.

Precipitation data for stations within the modeling domain for the January 1999 through January 2000 period was also incorporated into the analysis.

II.1.5 Results and Conclusions

A. Near Field Results

The Applicant performed a series of near-field analyses to estimate the impact from the proposed project and other sources operating in the area of study. The impact area of study for a NAAQS and PSD increments analysis is considered to be any location where a pollutant is predicted to cause a significant ambient impact. The impact area is defined as a circular area with a radius extending from the source to the most distant point where a significant impact is predicted to occur. The maximum distances for each pollutant above the significance levels were 22.4 kilometers for NO₂, 12.5 kilometers for SO₂, and 1.6 kilometers for PM₁₀. Per

federal modeling guidance, an additional distance of 50 kilometers was added to each radius to define the scope of the full impact analysis.

For the NAAQS and PSD Class II analyses, the second highest modeled predicted concentration for each pollutant's averaging period of 24 hours or less was selected for comparison to the applicable analysis' threshold level. Reported values for the annual average concentration and all other short-term averaging period analyses, are based on the predicted maximum concentration for that period.

1. Pre-Construction Monitoring Modeling

The Applicant performed a pre-construction modeling analysis to determine if impacts from the proposed source would result in a significant increase in airborne concentration in the area surrounding the facility. The analysis indicated that potential increases in concentration levels of NO₂, SO₂, and CO were less than the pre-construction monitoring trigger levels listed in R307-405(6)(2)(a)(i)(B). Therefore, no pre-construction monitoring of these pollutants was required. The predicted increase in the concentration level of PM₁₀ was above the pre-construction monitoring trigger level, supporting the Applicant's decision to perform one year of PM₁₀ onsite ambient monitoring. The pre-construction analysis was reviewed by the Division and determined to be consistent with the requirements of R307-410-2. Table II-3 below provides a comparison of the predicted air quality concentrations and monitoring trigger levels.

Table II-3: Model Predicted Pre-Construction Monitoring Concentrations

Pollutant/ Averaging Period	Predicted Concentration ($\mu\text{g}/\text{m}^3$)	Monitoring Trigger Level ($\mu\text{g}/\text{m}^3$)	Monitoring Required
NO ₂ - Annual	2.5	14	No
SO ₂ - 24-Hour	9.5	13	No
PM ₁₀ - 24-Hour	14.1	10	Yes
CO - 8-Hour	57.8	575	No

2. National Ambient Air Quality Standards Analysis

The Applicant performed a modeling analysis to determine if the combined impact from the proposed source, other industrial sources operating in the area, and ambient background would comply with federal NAAQS. The NAAQS analysis was reviewed by the Division and determined to be consistent with the requirements of R307-410-2. The analysis indicated that concentration levels of NO₂, SO₂, and CO resulting from the proposed project when combined with other industrial sources and ambient background, would comply with federal standards. For PM₁₀, the analysis indicated that total combined concentration levels would comply with federal standards in areas where the Applicant contributes a significant impact. Table II-4 provides a comparison of the predicted air quality concentrations and NAAQS.

Table II-4: Model Predicted NAAQS Concentrations

Pollutant/ Averaging Period	Model Predicted Conc. ($\mu\text{g}/\text{m}^3$)	Back- ground Conc. ($\mu\text{g}/\text{m}^3$)	Total Predicted Conc. ($\mu\text{g}/\text{m}^3$)	NAAQS ($\mu\text{g}/\text{m}^3$)
NO ₂ – Annual	24	10	34	100
SO ₂ – 3-Hour	75	20	95	1300
SO ₂ – 24-Hour	14	10	24	365
SO ₂ – Annual	2	5	7	80
PM ₁₀ – 24-Hour	14.1*	78	92.1*	150
PM ₁₀ – Annual	4.2*	29	33.2*	50
CO –1-Hour	271	1150	1420	40,000
CO – 8-Hour	58	1150	1208	10,000

* Maximum predicted concentration in areas where the Applicant has a significant impact

Results of the NO₂ annual impact analysis indicate that the maximum impact from the proposed project would occur in elevated terrain along the Pavant Range, eight kilometers north of the proposed site, and one kilometer west of Aurora, Utah. Predicted annual impacts are consistent with the prevalent up/down valley flows found in wind data collected onsite for the analysis.

For SO₂ 3-hour and 24-hour averaging periods, the maximum predicted impacts from the proposed project would occur in elevated terrain along the Pavant Range, four kilometers west of the site. Both predicted impacts are the result of light east winter winds moving down off the Sevier Plateau, with limited vertical mixing due to neutral to stable atmospheric conditions producing a shallow mixing layer over the Sevier Valley. Predicted annual impacts mimic those for NO₂, and are consistent with the prevalent up/down valley flows.

For CO 1-hour and 8-hour averaging periods, the maximum predicted impacts from the proposed project would occur in elevated terrain along the benches of the Sevier Plateau east of the proposed site. Predicted impacts are the result of light winds with limited vertical mixing.

For PM₁₀ the 24-hour and annual cumulative analysis showed several areas of elevated concentration. Additional analyses performed by the Applicant determined that the proposed coal-fired power plant project would not significantly contribute to these elevated areas. Maximum predicted concentrations in areas where the Applicant has a significant impact would occur along the eastern edge of the proposed site's property boundary, and is a result of coal handling processes at the plant.

3. PSD Class II Increments

The Applicant performed a modeling analysis to determine if the combined impact from the proposed source and other increment consuming sources operating in the area would comply with PSD Class II increments. The analysis was reviewed by the Division and determined to be consistent with the requirements of R307-410-2. The analysis indicated that concentration levels of NO₂, SO₂, and PM₁₀ resulting from the proposed project, when combined with other increment consuming sources, would comply with Class II increments.

Table II-5 below provides a comparison of the predicted concentrations and PSD Class II increments. The increment analysis indicated that the amount of increment consumed by the proposed project would be less than 50% of the ceiling; therefore, approval under R307-401-6(3) from the Utah Air Quality Board would not be required.

Table II-5: Model Predicted PSD Class II Increment Concentrations

Pollutant/ Averaging Period	Predicted Concentration ($\mu\text{g}/\text{m}^3$)	PSD Class II Increment ($\mu\text{g}/\text{m}^3$)	% of PSD Class II Increment
NO ₂ – Annual	11.5	25	46
SO ₂ – 3-Hour	57.4	512	11
SO ₂ – 24-Hour	9.5	91	10
SO ₂ – Annual	1.0	20	5
PM ₁₀ – 24-Hour	14.1	30	47
PM ₁₀ – Annual	4.2	17	25

Results of the NO₂ annual impacts analysis indicate that the maximum impact would occur east of the proposed site. A search of the UDAQ Emissions Inventory database did not reveal any other significant increment consuming NO₂ sources within the required 72.4-kilometer radius of study.

For SO₂ 3-hour, 24-hour, and annual averaging periods, the location of the maximum predicted increment consumption by the proposed project was similar in location to the NAAQS analysis. This analysis only included emissions from the proposed project. A search of the UDAQ Emissions Inventory database did not reveal any other significant increment consuming SO₂ sources within the required 62.5-kilometer radius of study.

For PM₁₀, the analysis only included emissions from the proposed project. The UDAQ Emissions Inventory database did not reveal any other significant increment consuming PM₁₀ sources within the required 51.6-kilometer radius of study. Results of the PM₁₀ 24-hour and annual analysis showed the highest point of impact to occur along the east property boundary of the proposed site.

4. Hazardous Air Pollutants

The Applicant performed a modeling analysis to determine the impact from HAPs released by the proposed source on the surrounding area. The analysis is shown below as Table II-6.

Table II-6: Hazardous Air Pollutant Analysis

Pollutant	Emission Threshold Values										Acute TLV/10	Chronic TLV/30	Carcinogenic TLV/90	Model or Not	
	Boiler Emissions (lb/hr)	Fire Pump Emissions (lb/hr)	Generator Emissions (lb/hr)	Vertically Unrestricted			TWA (ppm)	TLV (mg/m ³)	MW	ETF					ETV (lb/hr)
				Acute	Chronic	Carcinogenic									
biphenyl*	1.90E-04				x		0.2	1.267	154.2	0.368	0.46		0.042	no	
naphthalene*	1.45E-03	2.48E-04	2.48E-04		x		10	52.434	128.2	0.368	19.30		1.748	no	
acetaldehyde*	6.36E-03	4.81E-05	4.81E-05	x			25	45.092	44.7	0.31	13.98	4.51		no	
acetophenone*	1.67E-03				x		10	49.141	120.15	0.368	19.03		1.638	no	
acrolein*	3.23E-03	1.51E-05	1.51E-05	x			0.1	0.229	56.1	0.31	0.07	0.02		no	
benzene*	1.45E-01	1.48E-03	1.48E-03				2.5	7.996	78.1	0.31	2.48		0.266	no	
benzyl chloride*	7.81E-02				x		1	5.178	126.6	0.368	1.91		0.173	no	
bis(2-ethylhexyl)phthalate*	8.14E-03					x	5	79.865	390.56	0.123	9.82		0.887	no	
bromoform*	4.36E-03				x		0.5	5.170	252.8	0.368	1.90		0.172	no	
carbon disulfide*	1.45E-02				x		10	31.128	76.1	0.368	11.45		1.037	no	
2-chloroacetophenone*	7.81E-04				x		0.05	0.316	154.6	0.368	0.12		0.011	no	
chlorobenzene*	2.45E-03				x		10	46.053	112.6	0.368	16.95		1.535	no	
chloroform*	6.58E-03				x		10	48.875	119.5	0.368	17.99		1.629	no	
cumene*	5.91E-04				x		50	245.808	120.2	0.368	90.46		8.194	no	
2,4-dinitrotoluene*	3.12E-05				x			0.2	182.15	0.368	0.07		0.007	no	
dimethyl sulfate*	5.35E-03				x		0.1	0.516	126.1	0.368	0.19		0.017	no	
ethyl benzene*	1.05E-02			x			125	542.740	106.16	0.31	168.25	54.27		no	
ethyl chloride*	4.68E-03				x		100	263.885	64.52	0.368	97.11		8.795	no	
ethylene dichloride*	4.46E-03				x		10	40.474	98.96	0.368	14.89		1.349	no	
ethylene dibromide*	1.34E-04				x		NA	NA	187.88	0.368	NA	NA		NA	
formaldehyde*	2.68E-02	1.51E-04	1.51E-04	x			0.3	0.368	30.03	0.31	0.11	0.04		no	
hexane*	7.47E-03				x		50	176.237	86.18	0.368	64.86		5.875	no	
isophorone*	5.47E-02			x			5	28.264	139.21	0.31	9.76	2.83		no	
methyl bromide*	1.78E-02				x		1	3.883	94.95	0.368	1.43		0.129	no	
methyl chloride*	5.81E-02			x			100	256.503	50.49	0.31	64.03	20.65		no	
methyl ethyl ketone*	4.35E-02			x			300	884.653	72.1	0.31	274.25	88.47		no	
methyl hydrazine*	1.90E-02				x		0.01	0.019	46.07	0.368	0.01		0.001	no	
methyl methacrylate*	2.23E-03			x			100	409.630	100.13	0.31	125.95	40.95		no	
methyl tert butyl ether*	3.90E-03				x		50	180.307	88.17	0.368	66.35		6.010	no	
methylen chloride*	3.23E-02				x		50	173.681	84.93	0.368	63.91		5.789	no	
phenol*	1.78E-03				x		5	19.245	94.11	0.368	7.08		0.642	no	
propionaldehyde*	4.24E-02				x		20	47.526	58.1	0.368	17.48		1.584	no	
tetrachloroethylene*	4.79E-03			x			100	678.119	165.8	0.31	210.22	67.81		no	
toluene*	2.68E-02	5.37E-04	5.37E-04			x	50	188.428	92.14	0.123	23.18		2.094	no	
1,1,1-Trichloroethane*	2.23E-03			x			450	2465.693	133.42	0.31	761.23	245.66		no	
styrene*	2.79E-03			x			40	170.405	104.16	0.31	62.83	17.04		no	
xylenes*	4.13E-03	3.69E-04	3.69E-04			x	150	651.288	106.16	0.123	80.11		7.237	no	
vinyl acetate*	8.47E-04			x			15	52.816	86.09	0.31	16.37	5.28		no	
HCl*	4.01E+00			x			2	2.993	36.47	0.31	0.92	0.30		yes	
HF	2.11E+00			x			3	2.455	20.01	0.31	0.76	0.25		yes	
antimony*	2.01E-03				x		0.1	0.600	121.75	0.368	1.84E-01		0.017	no	
arsenic*	4.57E-02				x			0.010	74.92	0.368	3.68E-03		0.00033	yes	
beryllium*	2.34E-03				x			0.002	9.01	0.368	7.38E-04		0.00007	yes	
cadmium*	5.69E-03				x		0.0022	0.010	112.4	0.123	1.23E-03		0.0001	yes	
chromium*	2.90E-02				x		0.2385	0.600	61.9	0.123	6.18E-02		0.006	no	
cobalt*	1.12E-02				x		0.0083	0.020	59.93	0.368	7.35E-03		0.001	yes	
manganese*	5.46E-02				x		0.5890	0.200	84.94	0.368	7.35E-03		0.007	no	
mercury*	9.25E-03			x			0.0037	0.030	300.59	0.31	9.30E-03	0.003		no	
nickel*	3.12E-02					x	0.6247	1.600	89.71	0.123	1.88E-01		0.017	no	
selenium*	1.45E-01				x		0.0519	0.200	79.96	0.368	7.35E-02		0.007	yes	

The analysis was reviewed by the Division and determined to be consistent with the requirements of R307-410-2. The analysis indicated that predicted concentrations of arsenic, beryllium, cadmium, cobalt, selenium, hydrogen fluoride and hydrogen chloride from the proposed project would be less than the UDAQ-Toxic Screening Levels (TSLs), and no further documentation of impacts would be required. Table II-7 below provides a comparison of the predicted HAP concentrations and UDAQ-TSLs.

Table II-7: Model Predicted Hazardous Air Pollutant Concentrations

Sevier Power Project HAPS Analysis

Pollutant	Type	lb/hr	g/sec	Modeled Max. 1-hour (µg/m3)	Modeled Max. 24-hour (µg/m3)	Acute (TLV/10) (mg/m3)	Chronic (TLV/30) (mg/m3)	Carcinogen (TLV/90) (mg/m3)	% of TLV
HCl	acute	4.014	5.06E-01	3.67		0.3			1.22
HF	acute	2.11	2.66E-01	1.932		0.25			0.77
arsenic	chronic	4.57E-02	5.76E-03			0.0047	0.00033		1.42
beryllium	chronic	2.34E-03	2.95E-04			0.0024	0.00007		3.43
cadmium	carcin.	5.69E-03	7.16E-04			0.00059		0.0001	0.59
cobalt	chronic	1.12E-02	1.40E-03			0.00115	0.001		0.12
selenium	chronic	1.45E-01	1.83E-02			0.01492	0.007		0.21

Acute - 1-hr averaging period compared against 1/10 TLV-C
 Chronic - 24-hr averaging period compared against 1/30 TLV-TWA
 Carcinogen - 24-hr averaging period compared against 1/90 TLV-TWA

B. Far-Field Results

The Applicant performed a series of far-field analyses to estimate the impact from the proposed project on six Class I areas in southern Utah and southwest Colorado.

1. PSD Class I Increment Consumption Analysis

The Applicant performed a modeling analysis to determine if the impact from the proposed source would comply with federal PSD Class I increments. The analysis indicated that concentration levels of NO₂, SO₂, and PM₁₀ would comply with PSD Class I increments. Model predicted concentrations for the proposed project were less than the UDAQ accepted Class I Significant Impact Levels (SIL), and no further analysis was required. The analysis was reviewed by the Division and determined to be consistent with the requirements of R307-410-2. Table II-8 below provides a comparison of the maximum predicted air quality concentrations at the six Class I areas included in the analysis with the Class I increments and significant impact levels. Detailed model predicted impacts for each of the five Utah Class I areas are outlined in Table 7-18 of the NOI.

Table II-8: Model Predicted PSD Class I Increment Concentrations

Pollutant/ Averaging Period	Predicted Concentration ($\mu\text{g}/\text{m}^3$)	Class I SIL ($\mu\text{g}/\text{m}^3$)	% of Class I SIL	PSD Class I Increment ($\mu\text{g}/\text{m}^3$)	% of PSD Class I Increment
NO ₂ – Annual	.012	0.1	12.0%	2.5	0.5%
SO ₂ – 3-Hour	0.781	1	78.1%	25	3.1%
SO ₂ – 24-Hour	0.144	0.2	72.0%	5	2.9%
SO ₂ – Annual	0.0082	0.1	8.2%	2	0.4%
PM ₁₀ – 24-Hour	0.0514	0.3	17.1%	8	0.6%
PM ₁₀ – Annual	.004	0.2	2.0%	4	0.1%

2. Visibility – Plume Blight

The Applicant performed a VISCREEN Level 1 and 2 analyses to determine if plumes emanating from the proposed project would be visible from the six Class I areas. The analysis was reviewed by the Division and determined to be consistent with the requirements of R307-410-2. Results of the analysis indicate that the plume emanating from the proposed project are within acceptable limits inside the six Class I areas.

3. Visibility – Regional Haze

The Applicant performed an analysis, consistent with the recommendations outlined in the Federal Land Manager's FLAG Report, to determine if emissions from the proposed project would result in a notable reduction to background visual range within the six Class I areas. Results from the CALPUFF modeling analysis were processed using the CALPOST post-processing module to calculate the change in background extinction (b_{ext}). In doing so, the Applicant used seasonal relative humidity factors ($f(\text{RH})$) for the areas of study, as provided in the FLAG guidance document. Results of this analysis indicated that the predicted change in b_{ext} would be less than the 5% threshold that is used to determine if a cumulative analysis is

required, in all Class I areas except one; Capitol Reef National Park.

Flag guidance allows for further refinement of the b_{ext} value by incorporating hourly relative humidity data measured at meteorological monitoring sites located near the Class I area of concern. The analysis refinement was reviewed by the Division and determined to be consistent with the requirements of R307-410-2. Results of the refined haze analysis indicated that the predicted change in b_{ext} in Capitol Reef NP would be less than the 5% threshold provided in FLAG; and therefore, no further analysis was required. Table II-9 below provides a comparison of the maximum predicted change in background extinction for the six Class I areas included in the analysis and the FLAG b_{ext} threshold used to determine if a cumulative analysis is required.

Table II-9: Model Predicted Regional Haze Impacts

National Park/ Wilderness Area	Predicted b_{ext} (%)	Cumulative Analysis Threshold (%)
Canyonlands National Park	3.63	5
Zion National Park	1.52	
Arches National Park	3.44	
Bryce Canyon National Park	2.69	
Capitol Reef National Park	4.26*	
Weninuche Wilderness Area	0.67	

* b_{ext} values based on hourly RH measured near Capitol Reef

4. Soils and Vegetation Analysis

The Applicant performed an analysis to determine the extent of impacts from the proposed source on soil and vegetation in the Class I areas. Along with a discussion of soils and vegetation, the Applicant performed an analysis to predict deposition rates of sulfates and nitrates in these areas. The CALPUFF model was used to predict wet and dry fluxes of SO_2 , SO_4 , HNO_3 , and NO_3 . The CALPOST post-processing module was then used to adjust for molecular weight, sum the total fluxes, and develop an average flux rate and annual deposition rate. Deposition rates were compared against the Deposition Analysis Threshold (DAT) recommended in the FLAG Report. The analysis was reviewed by the Division and determined to be consistent with the requirements of R307-410-2. Results of the analysis are listed in Table II-10 below.

Table II-10: Model Predicted Nitrate and Sulfate Deposition Rates

National Park/ Wilderness Area	Total Nitrate Deposition Rate (kg/ha/yr)	Total Sulfate Deposition Rate (kg/ha/yr)	Deposition Analysis Threshold (kg/ha/yr)
Canyonlands National Park	5.12 E-04	7.42 E-04	5.0 E-03
Zion National Park	5.36 E-04	6.47 E-04	
Arches National Park	3.75 E-04	6.00 E-04	
Bryce Canyon National Park	1.18 E-03	1.15 E-03	
Capitol Reef National Park	2.12 E-03	2.26 E-03	
Weninuche Wilderness Area	1.01 E-04	1.77 E-04	

5. Non-attainment Boundary Impact Analysis

The Applicant performed an analysis to determine if the combined impact of NO₂, SO₂, and PM₁₀ from the proposed source would exceed the threshold trigger levels outlined in R307-403-5, in the Utah County non-attainment area. Results from the CALPUFF analysis were processed using the CALPOST post-processing module to combine the predicted concentrations of the three pollutants. The analysis was reviewed by the Division and determined to be consistent with the requirements of R307-410-2. Results of the analysis indicated that the predicted impact on the non-attainment area would be below the threshold levels; and therefore, would not require emission offsets. Results of the analysis are listed in the Table II-11 below.

Table II-11: Model Predicted Utah County Non-Attainment Boundary Impacts

Pollutant/ Averaging Period	Predicted Concentration in The Utah County Non-attainment Area ($\mu\text{g}/\text{m}^3$)	Threshold Trigger Level to Require Offsets ($\mu\text{g}/\text{m}^3$)
NO ₂ - 24-Hour	0.323	NA
NO ₂ - Annual	0.013	
SO ₂ - 24-Hour	0.166	
SO ₂ - Annual	0.010	
PM ₁₀ - 24-Hour	0.054	
PM ₁₀ - Annual	0.003	
Total - 24 Hour	0.543	3
Total - Annual	0.026	1

III. BEST AVAILABLE CONTROL TECHNOLOGY (BACT) ANALYSIS

State and federal regulatory programs require the implementation of emissions controls for the proposed project. Utah requires a BACT determination be made for each individual new emissions unit and pollutant emitting activity at which a net emissions increase would likely occur. Individual BACT analyses are performed for each pollutant subject to a PSD review.

III.1 Applicability of Control Technology Requirements

A new facility in Utah, by law, must consider the best control of all the emissions. Control may be achieved by a) good process design, b) sound operating practices, c) best emission control devices available, or d) a combination of these controls. Utah Air Conservation Rule R307-401-6 indicates that an approval order will be granted if the following conditions have been met:

The degree of pollution control for emissions, to include fugitive emissions and fugitive dust, is at least best available control technology except as otherwise provided in the regulations.

As the rule states, BACT must be based on the most effective engineering techniques and control equipment necessary to minimize emissions of air contaminant to the outside environment from its process.

III.1.1 Pollutants Subject to BACT

A BACT analysis must be conducted for emissions of NO_x, CO, PM₁₀, VOC, SO₂, and sulfuric acid mist. BACT determinations are made on a case-by-case basis that involves an assessment of the availability of applicable technologies capable of sufficiently reducing a specific pollutant emission as well as economic, energy, and environmental impacts of using each technology.

III.2 Approach Used in BACT Analysis

A methodology used in this study to determine BACT follows the “top-down” approach. The “top-down” BACT analysis contains the following elements:

- ?? A determination of the most stringent control alternatives potentially available.
- ?? An assessment of the technical feasibility of each alternative.
- ?? An assessment of beneficial and adverse energy impacts, environmental impacts, and economic impacts of technically feasible alternatives.
- ?? Selection of the best technically feasible control alternative, considering the beneficial and adverse impacts of each.
- ?? Confirmation that the selected BACT is at least as stringent as applicable NSPS and SIP limits for the source.

EPA guidance recommends that the BACT analysis be conducted using 5 basic steps. These steps are applied sequentially for each emission unit and each pollutant as discussed below:

Step 1. Identify All Available Control Technologies. This is a compilation of all control technologies available and having the potential to reduce emissions of the pollutant in question. The list does not exclude technologies implemented outside the United States. Technologies required under lowest achievable emission

rate (LAER) determinations are available for BACT purposes and are included as control alternatives.

Step 2. Eliminate Technically Infeasible Options. Technically feasible control options are those that have been demonstrated to function efficiently on identical or similar processes. This demonstration, and the evaluation of what constitutes an “identical or similar” process, is based on physical, chemical, and engineering principles.

Step 3. Rank Remaining Control Technologies by Control Effectiveness. The remaining control alternatives not eliminated in Step 2 are ranked in order of most effective (i.e. lowest emission rate) to the least effective.

Step 4. Evaluate Most Effective Controls and Document Results. The information developed in Step 3 is objectively evaluated to determine whether economic, environmental, and energy impacts are sufficient to justify exclusion of the technology. The analysis begins with the top ranked technology and continues until the technology under consideration cannot be eliminated by any economic, environmental, and energy impacts, which justify that, the alternative is inappropriate as BACT.

Step 5. Select BACT. The most effective control option not eliminated in Step 4 is identified as BACT.

III.3 BACT for NO_x Emissions from Circulating Fluidized Bed Boilers

Nitrogen oxides are formed in combustion sources by the thermal oxidation in the combustion air and the reduction and subsequent oxidation of fuel nitrogen. Virtually all NO_x emissions originate as nitric oxide (NO) as both nitrogen and oxygen dissociate into atomic form at the high temperatures within the boiler and then recombine to form NO. A minor fraction of the NO is further oxidized in the flue gas system to form NO₂. The bulk of NO_x formation for this project will be through thermal oxidation of nitrogen from the combustion air or thermal NO_x.

The amount of fuel NO_x formed is dependent on the amount of nitrogen compounds in the coal and the amount of lime present in the boiler. The rate of formation of thermal NO_x is a function of the residence time, free oxygen, and peak flame temperature. Therefore, combustion techniques for managing the formation of thermal NO_x are aimed at minimizing one or more of these variables. Selective catalytic reduction (SCR) and Selective Non-Catalytic Reduction (SNCR) remove NO_x from the gas stream.

III.3.1 Step 1 - Identification of Potential Control Technology

Fluidized bed combustion boilers are inherently low NO_x emitters due to the relatively low combustion temperatures. For this project, the following control technologies have been identified for NO_x control:

1. Selective catalytic reduction
2. Selective non-catalytic reduction

III.3.2 Step 2 - Discussion of Technical Feasibility

Two combustion control technologies were identified for the proposed CFB boiler and are discussed in the following sections.

III.3.2.1 Selective Catalytic Reduction

The Selective Catalytic Reduction process involves post combustion removal of NO_x from the flue gas with a catalytic reactor. Ammonia (NH_3) is injected into the flue gas stream upstream of the catalyst bed and NO_x and NH_3 combine at the catalyst surface, forming elemental nitrogen and water. The function of the catalyst is to lower the activation energy of the NO_x decomposition reaction; the catalyst allows NO_x reduction to proceed at a lower temperature than that required for SNCR.

Selective catalytic reduction has been demonstrated to achieve high levels of NO_x reduction on several types of combustion sources, including pulverized coal and stoker-type coal-fired boilers, but has not been demonstrated on CFB boilers. This technology could potentially be transferred to a CFB boiler such as that at the proposed SPC project, but not without significant difficulty: SCR installation upstream of the baghouse is technically infeasible because the particulate matter loading upstream of the baghouse will contain a very high loading of alkaline particulate matter that would likely preclude effective SCR operation, and SCR installation downstream of the baghouse is technically infeasible because the exhaust gas temperature at that location is too low to support effective SCR operation.

An SCR system could be applied to the SPC project if another boiler technology, such as pulverized coal firing, were used instead of FBC boiler technology.

III.3.2.2 Selective Non-Catalytic Reduction

Selective non-catalytic reduction has been applied to a number of different types of combustion sources, including petroleum heaters, utility and industrial boilers fired with natural gas and oil, as well as Japanese and European PC boilers and domestic coal-fired CFBs.

The SCNR process is based on a gas-phase homogeneous reaction, within a specified temperature range, between NO_x in the flue gas and either injected NH_3 or urea to produce gaseous nitrogen and water vapor. SNCR systems do not employ a catalyst; the NO_x reduction reactions are driven by the thermal decomposition of ammonia and the subsequent reduction of NO_x . Consequently, the SNCR process operates at higher temperatures than the SCR process.

Critical to the successful reduction of NO_x with SNCR is the temperature of the flue gas at the point where the reagent is injected. For the ammonia injection process, the necessary temperature range is 1,700 - 1,900 °F. Also critical to effective application of these processes are gas mixing, residence time at temperature, and ammonia slip.

Theoretically, one mole of ammonia will react with one mole of NO_x forming elemental nitrogen and water. In reality, not all the injected reagent will react due to imperfect mixing, uneven temperature distribution, and insufficient residence time. These physical limitations may be compensated for by injecting a large amount of excess reagent and essentially achieving low NO_x emissions at the expense of emissions of unreacted reagent, referred to as 'slip'.

These emissions represent an adverse environmental impact and can lead to the formation of ammonium salts. Thus, for a given boiler configuration, there is a limit on the degree of NO_x reduction which can be achieved with SNCR while maintaining acceptable levels of slip.

The CFB design is described as the ideal application for SNCR in the available open literature. CFB boilers are

constant temperature, variable heat transfer devices. The bed temperature and downstream flue gas temperature can be set by the operator to within a few degrees. The typical temperature of CFB flue gas leaving the bed and entering the hot cyclone is at the ideal temperature for SNCR. Additionally, the reduction reagent is injected at the inlet to the hot cyclone, where all of the flue gas is swirled at 50-75 ft per second, and forced to change direction several times. This cyclonic action homogenizes the reagent flue gas NO_x concentration, thus, maximizing mixing.

III.3.3 Step 3 - Rank Remaining Technically Feasible Control Technologies by Control Effectiveness

Remaining control alternatives not eliminated in Step 2 are ranked in order of most effective (lowest emission rate) as follows:

1. SNCR
2. SCR

An SCR system could be applied to the SPC project if another boiler technology, such as pulverized coal firing, were used instead of FBC boiler technology. However, this technology substitution would not provide significant emission reduction below the level proposed to be achieved with CFB technology and SNCR, be inconsistent with the SO₂ and sulfuric acid mist BACT determinations, because the achievable SO₂ and sulfuric acid mist emission reductions with PC boiler technology are not as great as with CFB boiler technology, and

SNCR is preferred over SCR for the proposed CFB boiler since SNCR has been demonstrated to be effective, is operating on existing units, and has lower capital costs. SNCR has been utilized on CFB boilers at emission levels below the level expected at the SPC Project. However, attempting to achieve a lower level at the SPC Project is not considered technologically feasible.

The economic, environmental, and energy impacts associated with each technology are evaluated in the following section.

III.3.4 Step 4 - Evaluate Economic, Environmental, and Energy Impacts

The SPC Project will implement SNCR control technology, which is listed as a technically feasible control technology; thus, further review of economic, environmental, and energy impacts are not necessary.

III.3.5 Step 5 - Proposed NO_x BACT for CFB Boiler

A summary of facilities utilizing CFB boiler technology and employing SNCR for NO_x control is presented in Table III-1.

Table III-1
Comparison of CFB Boiler NO_x Emission Rates using SNCR

Facility	Heat Input MMBtu/hr	NO _x Emissions (Lb/MMBtu)	Fuel
Taunton Energy Center	1604.4	0.15	Eastern US Coal

Energy New Bedford Cogeneration	3342.0	0.15	Eastern US Coal
Energy New Bedford Cogeneration	1671.0	0.15	Eastern US Coal
Reliant Energy Mid-Atlantic Power	2532.0	0.15	Refuse Coal & No.2 Fuel Oil
AES Warrior Run	2070.0	0.10	Eastern US Coal
AES-PRCP	4922.7	0.10	Columbian Coal
Archer Daniels Midland (5&6)	1500.0	0.07 ¹⁾	Coal
Archer Daniels Midland (7&8)	1500.0	0.12	Coal
Archer Daniels Midland (9&10)	1500.0	0.12	Coal
York County Energy Partners	2500.0	0.125	Bituminous Coal
Northampton Generating Co.	1146.0	0.10	Anthracite Culm

1) Based on a 30-day rolling average.

The SPC Project has proposed to achieve a NO_x emission limit of 0.10 lb/MMBtu (rolling 24-hour average basis). Of the 17 facilities listed in EPA's RACT/BACT/LAER Clearinghouse and identified as utilizing CFB technology, 13 used SNCR for NO_x reduction. Other facilities using SNCR with low emissions include Archer Daniels Midland (0.07 lb/MMBtu based on a 30-day rolling average), Cogeneration National (30 ppm or approximately 0.05 lb/MMBtu), GWF Power Systems (0.074 lb/MMBtu), and BMCP (0.039 lb/MMBtu).

GWF Power Systems utilizes petroleum coke; thus, cannot be justifiable compared to the SPC facility. The Archer Daniels Midland facility NO_x limit of 0.07 lb/MMBtu on a 30-day rolling average is no more stringent than the proposed limit of 0.10 lb/MMBtu on a 24-hr average basis. Cogeneration National and GWF Power Systems operate small boilers, 49 MW and 20 MW, respectively, and are not indicative of the NO_x emission level achievable with a 270 MW plant such as that proposed for the SPC project.

The CFB design offers lower NO_x formation than other commercial boiler types due to the low combustion temperatures and staged air operation. Thermal NO_x formation increases dramatically at combustion temperatures exceeding 2000 °F. Thermal NO_x formation in CFBs is inherently limited by the low (1600-1700 °F) combustion temperatures. However, there are site-specific technical features of the proposed boiler, which must be considered in determining the lowest emission level, which SNCR is capable of meeting. This includes the fuel characteristics and other factors that affect NO_x emission rates, including CO and VOC emission rates. Evaluation of these facilities must consider the feasibility of lower NO_x emission levels in the context of CO and VOC emission levels since measures to decrease NO_x also increase formation of CO and VOC. Of the facilities with lower NO_x limits than proposed for the SPC Project, most had a higher CO and VOC emission limit than those proposed for SPC Project.

Therefore, the concept of BACT as it applies to NO_x must be reviewed in the context of CO, VOC, and SO₂

emissions as well.

The SPC Project will achieve a NO_x emission rate of 0.10 lb/MMBtu on a 24-hr average with the use of a CFB boiler in conjunction with SNCR. This is considered BACT control for NO_x emissions.

III.4 BACT for VOC Emissions from Circulating Fluidized Bed Boiler

Emissions of volatile organic compounds (VOCs) result from the incomplete combustion of carbon and organic compounds and are a function of oxygen availability, temperature, residence time, and turbulence. In general, VOCs can be controlled in two ways: (1) controlling combustion parameters in order to maximize complete combustion, and (2) flue gas catalytic oxidation. The control of VOCs must be optimized with the control of the boiler exit emissions of NO_x.

III.4.1 Step 1 - Identification of Potential Control Technology

There were two techniques identified for reducing VOCs in the flue gases: catalytic oxidation and combustion controls.

III.4.2 Step 2 - Discussion of Technical Feasibility

Two VOC control technologies were identified for the proposed CFB boiler and are discussed in the following sections.

II.4.2.1 Catalytic Oxidation

For catalytic oxidation, a catalyst is situated in the flue gas stream, which would lower the activation energy of a series of reactions where reactant species, such as VOC, are converted to carbon dioxide and water. The catalyst permits the combination of the reactant species at lower gas temperatures than would be required for uncatalyzed oxidation.

The catalyst would be located at a point where the gas temperature is within an acceptable range. In a CFB, this means that the catalyst grid would need to be installed at a point upstream of the particulate matter control device.

Catalyst non-selectivity is a problem for sulfur-containing fuels such as coal. Catalysts promote oxidation of SO₂ to SO₃. The amount of SO₂ conversion is a function of temperature and catalyst design. Under optimum conditions, formation of SO₃ can be minimized to 20% of inlet SO₂. Compared to the proposed emissions level, this level of conversion would increase H₂SO₄ emissions of more than 2,000 tons per year, which aside from the increased ambient air impacts would result in unacceptable amounts of corrosion to the air preheater and ductwork.

Based examination of the available literature, there is no evidence that catalytic oxidation technology has ever been applied to coal-fired units. This technology could potentially be transferred to a CFB boiler such as that at the proposed SPC project, but not without significant and possibly insurmountable difficulties. Consequently, catalytic oxidation systems were not considered technically feasible for this facility.

III.4.2.2 Combustion Controls

The other means of controlling VOC emissions is through the design and operation of the boiler in a manner so as to limit VOC formation. Such controls are commonly referred to as combustion controls. In general, a combustion control system seeks to maintain the proper conditions to ensure complete combustion through one or more of the following operation design features: low excess air, staged combustion, overfire air, sufficient residence time, and good mixing. In the case of the propose SPC Project CFB, the boiler itself will incorporate design features which enhance uniform fuel/air distribution and mixing, along with oxygen monitoring and adjustment of the staged air combustion to suppress CO formation which also has the by-product of reducing VOC emissions.

III.4.3 Step 3 - Rank Remaining Technically Feasible Control Technologies by Control Effectiveness

Remaining control alternatives not eliminated in Step 2 are ranked in order of most effective (lowest emission rate). The only technically feasible control option for VOC control was the use of combustion controls.

III.4.4 Step 4 - Evaluate Economic, Environmental, and Energy Impacts

The SPC Project will implement combustion controls to reduce VOC emissions; thus, further review of economic, environmental, and energy impacts is not necessary.

III.4.5 Step 5 - Proposed VOC BACT for CFB Boiler

Table III-2 presents a summary of facilities utilizing CFB boiler technology and and their VOC emission limits. All listed facilities use combustion controls for minimizing VOC emissions.

Table III-2
Comparison of CFB Boiler VOC Emission Rates Using Combustion Controls

Facility	Heat Input MMBtu/hr	VOC Emissions (Lb/MMBtu)	Fuel
Taunton Energy Center	1604.4	0.006	Eastern US Coal
Energy New Bedford Cogeneration	3342.0	0.13	Eastern US Coal
Energy New Bedford Cogeneration	1671.0	10.55 ¹⁾	Eastern US Coal
Reliant Energy Mid-Atlantic Power	2532.0	0.005	Refuse Coal & No.2 Fuel Oil
AES Warrior Run	2070.0	0.005	Eastern US Coal
AES-PRCP	4922.7	0.10	Columbian Coal
Archer Daniels Midland (5&6)	1500.0	0.0072 ²⁾	Coal

Archer Daniels Midland (7&8)	1500.0	0.032	Coal
Archer Daniels Midland (9&10)	1500.0	0.032	Coal
York County Energy Partners	2500.0	0.004	Bituminous Coal
Northampton Generating Co.	1146.0	0.005	Anthracite Culm

- 1) Emission rate in lb/hour for any load.
- 2) Emission rate based on a 3-hour average.

The lowest emission limit reported (0.004 lb VOC/MMBtu) was the for York County Energy Partners facility. This is the only identified, comparable facility with a VOC emission limit lower than 0.005 lb/MMBtu. For the SPC Project, the applicant has proposed (based on the boiler manufacturer's guarantee) an emission rate of 0.005 lb VOC/MMBtu.

As discussed in Section III.3, the rates of formation of NO_x and VOC in a CFB boiler are inversely related, and the achievable NO_x and VOC emission levels must be assessed in tandem. While the York County Energy Partners facility did show a lower emission value, slight differences in combustion control settings for different elevations, humidity, and air density can result in slightly different values of VOC emissions. As combustion control also plays a role in the emissions of other pollutants, changing the combustion settings for a small decrease in VOC control might result in much larger increases in the emissions of NO_x. As can be seen in Table III-1, the NO_x emission limit for the York County Energy Partners facility is 0.125 lb/MMBtu, which is 25 percent higher than the proposed NO_x BACT limit of 0.10 lb/MMBtu for the SPC CFB boiler. There is no indication that a CFB boiler achieving the proposed NO_x emission level of 0.10 lb/MMBtu can also achieve a VOC emission level of 0.004 lb/MMBtu. Adopting a lower VOC emission limit of 0.004 lb/MMBtu and increasing the NO_x BACT emission level to 0.125 lb/MMBtu would result in a 63 tpy increase in allowable NO_x emissions from the proposed SPC CFB boiler. This is considered to be an unacceptable, adverse environmental impact.

Since the SPC Project will employ the same controls permitted for VOCs from sources in the Clearinghouse, and since the proposed level of emissions is the one of the lowest levels given for similar fuel being fired, boiler size, and operating conditions, 0.005 lb/MMBtu is considered representative of BACT in this case.

III.5 BACT for PM/PM₁₀ Emissions from Circulating Fluidized Bed Boiler

The composition and amount of particulate matter emitted from coal-fired boilers are a function of firing configuration, boiler operation, coal properties, and emission controls. Particulate matter (as total suspended particulate) will be emitted from the CFB boiler as a result of entrainment of incombustible inert matter (ash) and condensable substances. Since CFB boilers attain nearly complete combustion, very little carbon will be present.

III.5.1 Step 1 - Identification of Potential Control Technology

Two potential technologies were identified for the control of particulate from coal-fired boilers and are:

1. Fabric filtration
2. Electrostatic Precipitation

III.5.2 Step 2 - Discussion of Technical Feasibility

The two PM control technologies identified above for the CFB boiler are discussed in the following sections.

III.5.2.1 Fabric Filtration

The major particle collection mechanisms of fabric filters are inertial impaction, diffusion from Brownian motion, and interception. During fabric filtration, dusty gas is drawn through the fabric by forced-draft fans. The fabric is responsible for some filtration, but more significantly it acts as support for the dust layer that accumulates. The layer of dust, also known as a filter cake, is a highly efficient filter, even for sub-micrometer particles. Woven fabrics rely on the filtration abilities of the dust cake much more than felted fabrics.

Fabric filters possess some key advantages over other types of particle collection devices. Along with the very high collection efficiencies, they also have the flexibility to treat many types of dusts and a wide range of volumetric gas flows. Fabric filters can be operated with low pressure drops. Fabric filters also have some potential disadvantages. In general, they are limited to filtering dry streams.

III.5.2.2 Electrostatic Precipitation

Collection of particles by electrostatic precipitation involves the ionization of the stream passing through the electrostatic precipitator (ESP), the charging, migration, and collection of particles on oppositely charged surfaces, and the removal of particles from the collection surface. In dry ESPs, the particulate is removed by rappers, which vibrate the collection surface. Wet ESPs use water to rinse the particles off.

The control of PM using either fabric filtration or electrostatic precipitation is clearly demonstrated, available, and applicable to CFB boilers. This finding is consistent with general scientific thought that fabric filters and ESPs represent technically feasible control options for the control of particulate and trace metals from CFB boilers. Wet control techniques (scrubbers) do not represent a demonstrated control technique for CFB boilers and do not offer more stringent levels of control of particulate matter than fabric filters (EPA, 1985).

III.5.3 Step 3 - Rank Remaining Technically Feasible Control Technologies by Control Effectiveness

Remaining control alternatives not eliminated in Step 2 are ranked in order of most effective (lowest emission rate) as follows:

1. Fabric Filtration
2. Electrostatic Precipitation

Recent studies, conducted by Sjostrom, Bustard, et al, for the EPA and Department of Energy suggest that fabric filters achieve a much higher mercury removal when compared to ESPs. For sub-bituminous coal, the percentage of mercury removed was 70% by fabric filtration versus 9% by electrostatic precipitation. In addition, while both technologies offer similar removal properties for particulate matter, the PM emission level demonstrated to be achievable by CFB boilers equipped with baghouses is slightly lower than that demonstrated to be achievable by CFB boilers with ESP's. For these reasons, baghouses are considered the top control option.

III.5.4 Step 4 - Evaluate Economic, Environmental, and Energy Impacts

The SPC will employ fabric filters as the control device to reduce PM and trace metal emissions; thus, further review of economic, environmental, and energy impacts is not necessary.

III.5.5 Step 5 - Proposed PM BACT for CFB Boiler

Table III-3 presents a summary of filterable PM emission limitations¹ for facilities utilizing CFB boiler technology.

Table III-3
Comparison of CFB Boiler PM Emission Rates

Facility	Heat Input MMBtu/hr	PM Emissions (Lb/MMBtu)	Fuel
Taunton Energy Center	1604.4	0.018	Eastern US Coal
Energy New Bedford Cogeneration	3342.0	0.018	Eastern US Coal
Energy New Bedford Cogeneration	1671.0	NA	Eastern US Coal
Reliant Energy Mid-Atlantic Power	2532.0	0.010	Refuse Coal & No.2 Fuel Oil
AES Warrior Run	2070.0	0.015	Eastern US Coal
AES-PRCP	4922.7	0.015	Colombian Coal
Archer Daniels Midland (5&6)	1500.0	0.015	Coal
Archer Daniels Midland (7&8)	1500.0	0.025	Coal
Archer Daniels Midland (9&10)	1500.0	0.025	Coal
York County Energy Partners	2500.0	0.011	Bituminous Coal
Northampton Generating Co.	1146.0	0.010	Anthracite Culm

With the exception of the AES-PRCP plant, all other plants operating CFB boilers and presented in Table III-3 utilize fabric filters for control of PM emissions.

¹ Only filterable PM₁₀ emissions are considered in this analysis because insufficient data are available to quantify the condensible PM₁₀ emissions from coal-fired CFB boilers.

The facilities reporting the lowest PM emission limit were the Reliant Energy Mid-Atlantic Power and Northampton Generating Company with emission limits of 0.010 lb/MMBtu. York County Energy Partners reported an emission limit of 0.011 lb/MMBtu. These three companies burn different coal types than those proposed for the proposed SPC project so a straight comparison between these facilities and the proposed SPC project cannot be made. The boiler manufacturer for the SPC Project can guarantee an emission rate of 0.015 lb/MMBtu based on the design coal with a sulfur content of 0.4% and 0.016 lb/MMBtu based on a coal sulfur content of 0.7% and boiler operation. Hence, the SPC Project is proposing an emission limit of 0.015 lb/MMBtu, which is considered representative of BACT for control of PM₁₀ emissions from CFB boilers.

III.6 BACT for CO Emissions from Circulating Fluidized Bed Boiler

Emissions of CO result from the incomplete combustion of carbon and organic compounds. CO emissions are a function of oxygen availability (excess air), flame temperature, residence time at flame temperature, combustor design, and turbulence. Control of the emissions of CO may be effected two ways: (1) combustion modifications to minimize the formation of the pollutant, and (2) flue gas oxidation of any CO formed in the combustion process.

III.6.1 Step 1 - Identification of Potential Control Technology

Control technologies for CO from combustion sources are the same two control technologies identified in the VOC BACT discussion in Section III.4: combustion controls and catalytic oxidation.

III.6.2 Step 2 - Discussion of Technical Feasibility

For the reasons outlined in Section III.4.2, combustion controls are considered technically feasible and catalytic oxidation is considered technically infeasible for the CFB boiler at the SPC project.

III.6.3 Step 3 - Rank Remaining Technically Feasible Control Technologies by Control Effectiveness

Remaining control alternatives not eliminated in Step 2 are ranked in order of most effective (lowest emission rate) as follows:

1. Combustion Controls

The only technically feasible control option for CO control is through combustion controls.

III.6.4 Step 4 - Evaluate Economic, Environmental, and Energy Impacts

The SPC Project will implement combustion controls to reduce CO emissions; thus, further review of economic, environmental, and energy impacts is not necessary.

III.6.5 Step 5 - Proposed CO BACT for CFB Boiler

Table III-4 presents a summary of facilities utilizing CFB boiler technology and combustion controls for CO reduction. Combustion controls are the only control technologies that are specified for these facilities.

Table III-4

Comparison of CFB Boiler CO Emission Rates Using Combustion Controls

Facility	Heat Input MMBtu/hr	CO Emissions (Lb/MMBtu)	Fuel
Taunton Energy Center	1604.4	0.13	Eastern US Coal
Energy New Bedford Cogeneration	3342.0	0.018	Eastern US Coal
Energy New Bedford Cogeneration	1671.0	228.1 ¹⁾	Eastern US Coal
Reliant Energy Mid-Atlantic Power	2532.0	0.15	Refuse Coal & No.2 Fuel Oil
AES Warrior Run	2070.0	0.15	Eastern US Coal
AES-PRCP	4922.7	0.10	Colombian Coal
Archer Daniels Midland (5&6)	1500.0	0.15	Coal
Archer Daniels Midland (7&8)	1500.0	0.10	Coal
Archer Daniels Midland (9&10)	1500.0	0.10	Coal
York County Energy Partners	2500.0	NA	Bituminous Coal
Northampton Generating Co.	1146.0	0.15	Anthracite Culm

1) Emission rate in lb/hour for any load.

The lowest emission limit reported (0.018 lb VOC/MMBtu) was the Energy New Bedford Cogeneration facility. This is the only identified, comparable facility with a CO emission limit lower than 0.10 lb/MMBtu. For the SPC Project, the applicant has proposed (based on the boiler manufacturer's guarantee) an emission rate of 0.10 lb VOC/MMBtu.

As discussed in Section III.3, the rates of formation of NO_x and CO in a CFB boiler are inversely related, and the achievable NO_x and CO emission levels must be assessed in tandem. While the reported CO emission limit for the Energy New Bedford Cogeneration facility is more stringent than that proposed for the SPC project, slight differences in combustion control settings for different elevations, humidity, and air density can result in different CO emission rates. As combustion control also plays a role in the emissions of other pollutants, changing the combustion settings for a small decrease in CO control might result in much larger increases in the emissions of NO_x. As can be seen in Table III-1, the NO_x emission limit for the Energy New Bedford Cogeneration facility is 0.15 lb/MMBtu, which is 50 percent higher than the proposed NO_x BACT limit of 0.10 lb/MMBtu for the SPC CFB boiler. There is no indication that a CFB boiler achieving the proposed NO_x emission level of 0.10 lb/MMBtu can also achieve a CO emission level of 0.10 lb/MMBtu. Adopting a lower CO emission limit of 0.10 lb/MMBtu and increasing the NO_x BACT emission level to 0.15 lb/MMBtu would result in a 127 tpy increase in allowable NO_x emissions from the proposed SPC CFB boiler.

This is considered to be considered an unacceptable, adverse environmental impact.

Since the SPC Project will employ the same controls permitted for CO from sources in the Clearinghouse, and since the proposed level of emissions is the one of the lowest levels given for similar fuel being fired, boiler size, and operating conditions, 0.10 lb/MMBtu is considered representative of BACT in this case.

III.7 BACT for SO₂ and Sulfuric Acid Mist Emissions from Circulating Fluidized Bed Boiler

From fossil fuel-fired sources, emissions of SO₂, sulfuric acid mist, and hydrogen fluoride are generated from the release of sulfur and fluorine present in the fuel. Upon combustion, approximately 98% of sulfur in solid fuels is emitted as gaseous sulfur oxides. Uncontrolled emissions of SO₂ are affected by fuel sulfur content alone and not on the firing mechanism, boiler size, or operation. Similarly, uncontrolled emissions of fluorides (as hydrogen fluoride) are only affected by the fluoride content of the limestone or fuel. From the reaction of sulfur trioxide (SO₃) with water vapor outside of the combustion section, sulfuric acid mist is formed. Since the formation of SO₃ is a function of the generation of SO₂, uncontrolled emissions of sulfuric acid mist are also a function of the sulfur content of the coal.

Control of SO₂ and other acid gases is inherent to CFB operation. Second generation CFB combustors were developed specifically to utilize domestic coal in an environmentally acceptable manner. In a CFB boiler, sulfur released from fuel reacts in the combustion zone with lime and the gypsum (CaSO₄) product is removed from the flue gas in the particulate collector. The control of acid gases does not rely on downstream flue gas desulfurization.

III.7.1 Step 1 - Identification of Potential Control Technologies

Sulfur dioxide, sulfuric acid mist, and hydrogen fluoride, referred collectively as acid gases, are all controlled by the same technologies.

Control of SO₂ and acid gases is inherent to CFB operation. In a CFB boiler, sulfur oxides and other acid gases released from fuel react with calcium in the combustion zone. The reaction products, including gypsum (CaSO₄) and calcium fluoride, are removed from the flue gas in the particulate collector. Thus, the use of a CFB boiler with limestone injection is considered one control option.

The technical factors related to in-bed acid gas and reduced sulfur compound (SO₂, H₂SO₄, HF, HCl, H₂S) control with limestone include calcium to sulfur (Ca/S) ratio, reactivity of limestone, particle size, fuel properties, mixing, and gas-phase residence time. To a certain extent, these factors are related in that they are dependent on physical characteristics of the fuel and limestone used and the boilers that use them.

The second identified control option is the use of an add-on “scrubber” for removal of acid gases downstream of the combustion zone. For the purposes of this analysis, a circulating dry scrubber using lime injection is used to represent the “scrubber” control option. A circulating dry scrubber utilizes a gas-phase reaction between SO₂, H₂SO₄, and fluorides with hydrated lime in a fluid bed reactor placed downstream of the CFB boiler but upstream of the particulate matter control device. Gas enters the scrubber vessel at the bottom and flows vertically upward through a venturi section. Ash from the particulate matter control device is recirculated through the scrubber to optimize fresh lime consumption.

III.7.2 Step 2 - Discussion of Technical Feasibility

Both identified control options are technically feasible for the SPC Project.

III.7.3 Step 3 - Rank Remaining Technically Feasible Control Technologies by Control Effectiveness

The best technically feasible control option for control of acid gases involves the use of a CFB boiler with limestone injection in conjunction with a circulating dry scrubber using lime injection.

III.7.4 Step 4 - Evaluate Economic, Environmental, and Energy Impacts

The SPC Project has proposed to implement acid gas control using a CFB boiler with limestone injection, in conjunction with a circulating dry scrubber and low sulfur coal; thus, further review of economic, environmental, and energy impacts is not necessary.

III.7.5 Step 5 - Proposed SO₂ and Acid Gas BACT for CFB Boiler

Table III-5a presents a summary of SO₂ emission limits for facilities utilizing CFB boiler technology.

Table III-5a
Comparison of CFB Boiler SO₂ Emission Rates

Facility	Heat Input MMBtu/hr	SO₂ Emissions (Lb/MMBtu)	Control	Fuel
Taunton Energy Center	1604.4	0.23	Limestone	Eastern US Coal
Energy New Bedford Cogeneration	3342.0	0.23	Limestone	Eastern US Coal
Energy New Bedford Cogeneration	1671.0	0.23	Limestone	Eastern US Coal
Reliant Energy Mid-Atlantic Power	2532.0	0.60	Fly Ash Reinjection	Refuse Coal & No.2 Fuel Oil
AES Warrior Run	2070.0	0.16	Limestone	Eastern US Coal
AES-PRCP	4922.7	0.022	Limestone and dry scrubbing	Columbian Coal
Archer Daniels Midland (5&6)	1500.0	0.36	Limestone	Coal
Archer Daniels Midland	1500.0	0.70	Limestone	Coal

(7&8)				
Archer Daniels Midland (9&10)	1500.0	0.70	Limestone	Coal
York County Energy Partners	2500.0	0.25	Lime	Bituminous Coal
Northampton Generating Co.	1146.0	0.129	Lime	Anthracite Culm

The lowest SO₂ emission limit reported (0.022 lb/MMBtu, 3-hr average) was the AES-PRCP facility. This is the only identified, comparable facility with an SO₂ emission limit lower than 0.05 lb/MMBtu. The AES-PRCP utilizes a CFB boiler with limestone injection followed by a circulating dry scrubber for SO₂ control.

For the SPC Project, the applicant has proposed to use a CFB boiler with limestone injection followed by a circulating dry scrubber using lime injection, in conjunction with the use of low-sulfur coal. The applicant has proposed SO₂ BACT emission limits of 0.022 lb/MMBtu on a rolling 30-day average basis, based on a design coal sulfur content of 0.4%, and 0.05 lb/MMBtu on a rolling 24-hr average basis, based on worst-case coal sulfur content of 0.9%. While these proposed emission limits appear slightly less stringent than those imposed on the AES-PRCP facility, the proposed SPC Project actually will be required to achieve a higher control efficiency, because the AES-PRCP facility (in Puerto Rico) uses South American coal having a sulfur content less than 0.1%. The SO₂ removal efficiency required to achieve 0.022 lb/MMBtu on a 3-hr average basis, using coals available to the SPC project, has not been demonstrated to be achievable with any control technology. Therefore, SO₂ emission limits of 0.022 lb/MMBtu on a rolling 30-day average basis and 0.05 lb/MMBtu on a rolling 24-hr average basis are considered BACT in this case.

Table III-5b presents a summary of Sulfuric Acid Mist emission limits for facilities utilizing CFB boiler technology.

Table III-5b
Comparison of CFB Boiler Sulfuric Acid Mist Emission Rates

Facility	Heat Input MMBtu/hr	H ₂ SO ₄ Emissions (Lb/MMBtu)	Control	Fuel
Taunton Energy Center	1604.4		Limestone	Eastern US Coal
Energy New Bedford Cogeneration	3342.0		Limestone	Eastern US Coal
Energy New Bedford Cogeneration	1671.0		Limestone	Eastern US Coal
Reliant Energy Mid-Atlantic Power	2532.0		Fly Ash Reinjection	Refuse Coal & No.2 Fuel Oil

AES Warrior Run	2070.0		Limestone	Eastern US Coal
AES-PRCP	4922.7	0.0024	Limestone and dry scrubbing	Columbian Coal
Archer Daniels Midland (5&6)	1500.0		Limestone	Coal
Archer Daniels Midland (7&8)	1500.0		Limestone	Coal
Archer Daniels Midland (9&10)	1500.0		Limestone	Coal
York County Energy Partners	2500.0		Lime	Bituminous Coal
Northampton Generating Co.	1146.0		Lime	Anthracite Culm

The lowest emission limit reported (0.0024 lb/MMBtu) was the AES-PRCP facility. This is the limit proposed for the SPC Project. This limit is considered BACT in this case.

III.8 BACT for NO_x Emissions for Emergency Generator and Fire Pump

In an internal combustion (IC) engine NO_x can be formed two ways: (1) oxidation of atmospheric nitrogen found in the combustion air (thermal NO_x) and (2) the conversion of nitrogen chemically bound in the fuel (fuel NO_x).

Thermal NO_x forms in the combustion chamber when N₂ and O₂ molecules dissociate into free atoms at elevated temperatures and pressures encountered during combustion and then recombine to form NO. Thermal NO_x increases exponentially with increases in flame temperature and linearly with increases in residence time. The NO further oxidizes to NO₂ and other NO_x compounds downstream of the combustion chamber.

Fuel NO_x is formed when fuels containing bound nitrogen are burned. IC engines for this project will burn diesel fuel that typically contains little or no Fuel Bound NO_x (FBN). As a result, when compared to thermal NO_x, fuel bound NO_x is not a major contributor to overall NO_x emissions from most IC engines.

Factors that influence NO_x emissions include engine design and operating parameters, type of fuel, and ambient conditions.

III.8.1 Step 1 - Identification of Potential Control Technologies

Based on the data review process described in the beginning of this section and a review of the EPA

document, *Alternative Control Techniques for NO_x Emissions from Internal Combustion Engines*, a list of potential control technologies for controlling NO_x emissions from compression ignition, diesel fired internal combustion engines was formulated. The SPC Project has identified the following potential combustion control technologies:

1. Injection Timing
2. Retard Lean Burn Combustion
3. Selective catalytic reduction

III.8.2 Step 2 - Discussion of Technical Feasibility

Two combustion control techniques (injection timing retardation and lean burn) for the IC engines were identified as possible control technologies and are discussed in the following sections. A third control technology identified, selective catalytic reduction (SCR) is also discussed below as being a technically feasible control technology option.

III.8.2.1 Injection Timing Retardation

The operating pressures and temperatures in the combustion chamber are affected by adjusting the ignition timing in the power cycle. Advancing the timing so that ignition occurs earlier in the power cycle results in peak combustion when the piston is near the top of the chamber (when volume of the combustion chamber is at a minimum). This timing adjustment results in maximum pressures and temperatures and has the potential to increase NO_x emissions.

Conversely, retarding the ignition timing causes the combustion process to occur later in the power stroke when the piston is in the downward motion and combustion volume is increasing. Ignition timing retard action reduces operating pressures, temperatures, and residence time, which has the potential to reduce NO_x formation 20 to 30% on average. However, the exact magnitude of reduction is engine specific. Some of the limitations associated with retarded injection timing are related to the degree of retardation specific to the engines so that the greatest NO_x reduction can be achieved without causing performance impacts such as increased exhaust temperatures, decreased power output, misfiring, and elevated opacity at startup. Hence, the degree of timing retardation should be recommended by the manufacturer based on testing of similar size and type engines.

III.8.2.2 Lean Burn Combustion

A lean burn engine has an air-to-fuel ratio that is fuel lean and operates with high excess air, which reduces the peak temperature achieved, and gives an exhaust gas rich in oxygen. This inhibits the reaction responsible for thermal NO_x. Lean burn combustion engines may emit as much as 8% lower NO_x than rich burn or uncontrolled engines. Lean burn combustion is usually accomplished through special combustion features such as pre-combustion chamber and pre-stratifying the intake charge. Air/fuel ratio controllers are often used to maximize the reduction in emissions, increase engine efficiency, and maximize the power output. The only technical limitations associated with lean burn combustion are related to the optimal degree of lean combustion specific to the engines in order to achieve the greatest NO_x reduction. This should be recommended by the manufacturer based on testing of similar size and type engines.

III.8.2.3 Selective Catalytic Reduction

Selective catalytic reduction (SCR) is an add-on NO_x control technology that is placed in the exhaust stream following the engine. The SCR process reduces NO_x emissions by injecting ammonia into the exhaust upstream of a catalyst bed. The ammonia reacts with NO_x in the presence of a catalyst to form water and nitrogen. The operating range for SCR catalysts is typically 550 °F to 750 °F. Variations in exhaust gas temperature of 50 °F can have an impact on NO_x reduction efficiency. Also, the molar ratio of ammonia to NO_x is critical to NO_x reduction. Injection of ammonia at higher than the stoichiometric amount enhances NO_x reduction but results in higher ammonia emissions. The ammonia must be injected such that uniform distribution occurs across the catalyst bed.

Vendors indicated that NO_x reductions from 80-95% might be obtained through the implementation of SCR. SCR has only been installed on a very limited number of IC engines based on data in the EPA RBLC database. None of these engines are limited duty emergency use applications such as proposed for the SPC Project.

III.8.3 Step 3 - Rank Remaining Technically Feasible Control Technologies by Control Effectiveness

Remaining control alternatives not eliminated in Step 2 are ranked in order of most effective (lowest emission rate) as follows:

1. SCR
2. Combustion Controls

The economic, environmental, and energy impacts associated with each technology are evaluated in the following section.

III.8.4 Step 4 - Evaluate Economic, Environmental, and Energy Impacts

The analysis begins with the top ranked technology and continues until the technology under review cannot be eliminated by any economic, environmental, and energy impacts that justify that the alternative is inappropriate as BACT. The top ranked technology is SCR.

Initially, the SPC Project has only evaluated the annualized cost to install an SCR system based on the specifications and emission rates for the emergency generator and fire pump.

EPA's document (EPA-453/R-94-032) entitled, *Alternative Control Techniques (ACT) for NO_x Emissions from Internal Combustion Engines* was utilized to determine SCR capital installation costs. The costs were developed for a generator with the following operating specifications:

1. Rated capacity - 750 KW/(assume 1005) HP
2. Exhaust Flow Rate - 7 ft³/sec
3. Exhaust Temperature - 515 °C
4. Uncontrolled NO_x emission rate - 3.2 lb/MMBtu
5. NO_x reduction - minimum 80%
6. Ammonia slip - <10 ppm

The data were obtained from AP-42, Section 3.4 and from manufacturer specifications for similar generators.

An economic analysis was conducted based on the following capital and annualized cost algorithms from the previously referenced document:

Capitol cost = \$22,800 + (56.4 x hp) per unit

Annual operating cost = \$37,300 + (16.7 x hp) (for engines operating 500 hours or less).

For the proposed 1,005 horsepower engine the capital and annualized costs are \$79, 482 and \$54,083.50, respectively. Typically, control costs are evaluated based on cost effectiveness calculated as annual cost per ton of pollutant removed. Based on 80% removal efficiency for the oxidation catalyst per the above reference document, and an uncontrolled emission rate of approximately 1 TPY, the cost effectiveness of installing an SCR system on the emergency generator is over \$9 million per ton (total annual cost by annual tons of NO_x removed) of NO_x removed. Based on this cost estimate, the SPC Project believes the use of SCR would represent an adverse economic impact for the emergency generator and fire pump.

III.8.5 Step 5 - Proposed NO_x BACT for Emergency Generator and Fire Pump

The only remaining control technologies that are feasible for NO_x control for the emergency generators and fire pump are the combustion controls. The SPC Project will employ combustion controls (either ignition retarding and/or lean burn) as NO_x BACT to the maximum extent possible that engine specifications will allow. An economic evaluation of combustion controls is not necessary as it is the top ranked technically feasible control option.

III.9 BACT for VOC Emissions for Emergency Generator and Fire Pump

VOC emissions are discharged into the atmosphere as a result of incomplete combustion through the burning process and a small percentage is also emitted from fuel transfer/storage operations. Primary VOCs are hydrocarbons that are composed of a wide variety of organic compounds. Incomplete combustion usually occurs as a result of inadequate mixing of air and fuel, incorrect air/fuel ratios or “quenching” of the combustion products by the combustion chamber surfaces. A top down analysis to determine the best VOC control technology is provided in the following subsections.

III.9.1 Step 1 - Identification of Potential Control Technologies

After a review of pertinent literature and regulatory databases, a list of potential control technologies for controlling VOC emissions from compression ignition, diesel fired internal combustion engines was formulated. The SPC Project has identified the following potential combustion control technologies:

1. Positive Crankcase Ventilation
2. Good Combustion Practices

III.9.2 Step 2 - Discussion of Technical Feasibility

The control methods identified in the data search for emergency standby generators were positive crankcase ventilation and good combustion practices. These two combustion control techniques for VOC emissions are discussed in the following sections below.

III.9.2.1 Positive Crankcase Ventilation

The Positive Crankcase Ventilation (PCV) system uses a hose connected between the engine and the intake manifold to draw these gases out of the engine's crankcase and back into the cylinders to burn with the regular fuel. The only problem to solve is how to keep these gases from going willy-nilly into the manifold and upsetting the required air-fuel ratio. The solution to this problem is the PCV valve.

The PCV valve controls the release of crankcase gases and vapors to the intake manifold. The valve is kept closed by spring action when the engine is at rest. When the engine is running normally, the low vacuum it creates allows the valve to open and release crankcase vapors and gases into the intake manifold for burning. If the engine is idling or slowing down, the vacuum level rises and pulls the valve plunger into the valve opening. This partially blocks off the opening so that only a small amount of vapors and gases can be drawn into the intake manifold.

III.9.2.2 Good Combustion Practices

Good combustion practices serve to reduce VOC emissions by eliminating the causes of incomplete combustion. The engines will be designed to maximize combustion efficiency. The engine manufacturers will provide the SPC Project Operator and Maintenance manuals that will detail the methods to maintain a high level of combustion efficiency. Good combustion practices are technically feasible to control VOC emissions from the proposed engines.

III.9.3 Step 3 - Rank Remaining Technically Feasible Control Technologies by Control Effectiveness

Remaining control alternatives not eliminated in Step 2 are ranked in order of most effective (lowest emission rate) as follows:

1. PCV
2. Good Combustion Practices

III.9.4 Step 4 - Evaluate Economic, Environmental, and Energy Impacts

The SPC Project will implement all of the above listed technically feasible control technologies; thus, further review of economic, environmental, and energy impacts is not necessary.

III.9.5 Step 5 - Proposed VOC BACT for Emergency Generator and Fire Pump

The SPC Project will employ both PCV and good combustion practices to achieve a VOC emission rate of 0.53 lb/hr for the emergency generator and fire pump. These emission factors reflect the emission factors found in AP-42 Section 3.4 Large Stationary Diesel and Stationary Dual-Fuel Engines. Additionally, this equipment will be limited to 120 operating hours per year each.

III.10 BACT for PM/PM₁₀ Emissions for the Emergency Generator and Fire Pump

A top down analysis to determine the best PM/PM₁₀ control technology is provided in the following subsections. PM₁₀ emissions depend on the sulfur content and the combustion characteristics of the engine.

III.10.1 Step 1 - Identification of Potential Control Technology

Potential control technologies of PM emissions from diesel fired internal combustion engines include the following, ranked in order of potential effectiveness:

1. Positive Crankcase Ventilation
2. Add-on control (i. e. electrostatic precipitator, baghouse, scrubber)
3. Combustion of clean fuels
4. Implementation of good combustion practices.

III.10.2 Step 2 - Discussion of Technical Feasibility

The control methods identified in the data search for emergency standby generators are discussed in the following sections below.

III.10.2.1 Positive Crankcase Ventilation

The PCV system uses a hose connected between the engine and the intake manifold to draw these gases out of the engine's crankcase and back into the cylinders to burn with the regular fuel. The only problem to solve is how to keep these gases from going willy-nilly into the manifold and upsetting the required air-fuel ratio. The solution to this problem is the PCV valve.

The PCV valve controls the release of crankcase gases and vapors to the intake manifold. The valve is kept closed by spring action when the engine is at rest. When the engine is running normally, the low vacuum it creates allows the valve to open and release crankcase vapors and gases into the intake manifold for burning. If the engine is idling or slowing down, the vacuum level rises and pulls the valve plunger into the valve opening. This partially blocks off the opening so that only a small amount of vapors and gases can be drawn into the intake manifold. The literature suggests that a PCV system can reduce crankcase PM₁₀ emissions by at least 90% over an uncontrolled crankcase vent. The use of a PCV system may be technically feasible for the proposed engines.

III.10.2.2 Add-On Controls

No diesel-fired IC engines were identified in the permit review that utilized add-on control technology for PM/PM₁₀ control. In the EPA's *New Source Review Workshop Manual*, technically feasible control technology is technology that has been demonstrated commercially. No information was found that add-on PM/PM₁₀ control have been commercially demonstrated on IC engines, hence, this technology is not considered technically feasible for this application.

III.10.2.3 Combustion of Clean Fuels

Fuel combustion is responsible for significant emissions of PM/PM₁₀. The types of fuel and process have a great impact on the PM emissions from combustion. The combustion of clean fuels to minimize PM/PM₁₀ emissions is accomplished by burning fuels with minimal amounts of impurities in conjunction with good combustion practices. The SPC Project proposes to burn low sulfur diesel fuel (sulfur content 0.5% sulfur). Combustion of low sulfur fuel is technically feasible for the proposed engines.

III.10.2.4 Implementation of Good Combustion Practices

Good combustion practices refer to the operation of the engines at high combustion efficiency that reduce the product of incomplete combustion such as PM/PM₁₀. The engines will be designed to maximize combustion efficiency. The engine manufacturers will provide the SPC Project Operator and Maintenance manuals that will detail the methods to maintain a high level of combustion efficiency. Good combustion practices are technically feasible to control PM emissions from the proposed engines.

III.10.3 Step 3 - Rank Remaining Technically Feasible Control Technologies by Control Effectiveness

Remaining control alternatives not eliminated in Step 2 are ranked in order of most effective (lowest emission rate) as follows:

1. PCV
2. Good Combustion Practices
3. Combustion of Low Sulfur Fuels

III.10.4 Step 4 - Evaluate Economic, Environmental, and Energy Impacts

The SPC Project will implement all of the above listed technically feasible control technologies; thus, further review of economic, environmental, and energy impacts is not necessary.

III.10.5 Step 5 - Proposed PM/PM₁₀ BACT for the Emergency Generator and Fire Pump

The SPC Project will employ both PCV, good combustion practices, and utilize low sulfur content (0.05% sulfur) diesel fuel to achieve a PM₁₀ emission rate of 0.11 lb/hr for the emergency generator and fire pump. Additionally, these equipment will be limited to 120 operating hours per year.

III.11 BACT for CO Emissions for the Emergency Generator and Fire Pump

Carbon monoxide emissions are generated from incomplete combustion of the diesel fuel. These emissions occur when there is a lack of oxygen available, if the combustion temperature is too low, or if the residence time in the cylinder is too short. A top down analysis to determine the best available CO control technology is provided below.

III.11.1 Step 1 - Identification of Potential Control Technologies

Two potential control technologies were identified for CO control. These control technologies are:

1. Oxidation Catalyst
2. Good Combustion Practices

III.11.2 Step 2 - Discussion of Technical Feasibility

The control methods identified in the data search for emergency standby generator and fire pump were oxidation catalysts and good combustion practices. These two combustion control techniques for CO emissions are discussed in the following sections below.

III.11.2.1 Oxidation Catalyst

Oxidation catalysts, which are typically a precious metal deposited onto a solid honeycomb substrate, convert carbon monoxide to carbon dioxide in the presence of oxygen. A search of various regulatory databases did not show where this control method has been applied on similar emergency engines. Therefore, the SPC Project does not consider this technology a feasible option for CO emissions control.

III.11.2.2 Good Combustion Practices

Good combustion practices refer to the operation of engines at high combustion efficiency, thus reducing products of incomplete combustion such as CO. The engines will be designed to maximize combustion efficiency. The engine manufacturers will provide the SPC Project Operator and Maintenance manuals that will detail the methods to maintain a high level of combustion efficiency. Good combustion practices are technically feasible to control CO emissions from the proposed engines.

III.11.3 Step 3 - Rank Remaining Technically Feasible Control Technologies by Control Effectiveness

Remaining control alternatives not eliminated in Step 2 are ranked in order of most effective (lowest emission rate) as follows:

1. Good Combustion Practices

III.11.4 Step 4 - Evaluate Economic, Environmental, and Energy Impacts

The SPC Project will implement the above listed technically feasible control technology; thus, further review of economic, environmental, and energy impacts is not necessary.

III.11.5 Step 5 - Proposed CO BACT for Emergency Generator and Fire Pump

Based on the above evaluation, the SPC Project proposes good combustion practices as BACT. The proposed CO emission rate for the SPC Project is 4.1lb/hr for the generator and fire pump.

III.12 BACT for SO₂ Emissions for Emergency Generator and Fire Pump

Sulfur oxide (SO_x) emissions occur from the reaction of various elements in the diesel fuel. Regulatory database searches were conducted and only one control technique was identified for SO₂, which is the combustion of low sulfur fuels. For this reason, a top down analysis for SO₂ was not conducted. There was no evidence that add-on controls have been installed for SO₂ control from internal combustion engines; therefore, add-on controls are not considered as potential BACT for the proposed project.

The BACT for SO₂ for the emergency generator and fire pump will be based on combustion of low sulfur fuels. Since the only technically feasible alternative has been selected no economic analysis is required.

IV. APPLICABILITY OF FEDERAL REGULATIONS AND UTAH ADMINISTRATIVE CODES (UAC)

The Notice of Intent submitted is for a new source. At the time of this review the Utah Administrative Code Rules 307 (UAC R307) and federal regulations have been examined to determine their applicability to this Notice of Intent. The following rules have been specifically addressed.

1. R307-101-2, Major Modification - means any physical change in or change in the method of operation of a major source that would result in a significant net emissions increase of any pollutant.
2. R307-107, UAC - Unavoidable breakdown reporting requirements
3. R307-150 Series, UAC - Inventories, Testing and Monitoring. These rules cover emission inventory reporting requirements and require the owner or operator of sources of air pollution to submit an emissions inventory report:

R307-150. Emission Inventories
R307-155. Hazardous Air Pollutant
R307-158. Emission Statement Inventory.
4. R307-201-1(2), UAC - 20% maximum opacity limitation at all emission points. Visible emissions from installations constructed after April 25, 1971, except internal combustion engines, or any incinerator shall be of a shade or density no darker than 20% opacity, except as otherwise provided in these regulations.
5. R307-201-1(9), UAC - Opacity Observation.
6. R307-203-1(1), UAC - Commercial and Industrial Sources. Any coal, oil, or mixture thereof, burned in any fuel burning or process installation not covered by New Source Performance Standards for sulfur emissions shall contain no more than 1.0 pound sulfur per million gross Btu heat input for any mixture of coal nor .85 pounds sulfur per million gross Btu heat input for any oil.
7. R307-205 (UAC) - Emission Standards: Fugitive Emissions and Fugitive Dust.
8. R307-206, UAC - Abrasive Blasting Requirements - Opacity limitations and performance standards for abrasive blasting.
9. R307-305-5(1), UAC - Existing sources located in or affecting areas of non-attainment shall use reasonably available control measures to the extent necessary to insure the attainment and maintenance of the National Ambient Air Quality Standards (NAAQS).
10. R307-325-1(1) R307-325 applies to all sources in R307-326 through 341, major sources as defined and outlined in section 182 of the Clean Air Act and non-major sources located in Davis and Salt Lake Counties and in any non-attainment area for ozone as defined in the State

Implementation Plan.

11. R307-401-7, UAC - Rules for relocation of temporary sources.
12. R307-401-10(1), UAC - All sources excluding non-commercial residential dwellings shall install oxides of nitrogen control/low oxides of nitrogen burners or controls resulting from application of an equivalent technology, as determined by the Executive Secretary, whenever existing fuel combustion burners are replaced, unless such replacement is not physically practical or cost effective. The request for an exemption shall be presented to the Executive Secretary for review and approval.
13. R307-403-3, UAC - Every major new source or major modification must be reviewed by the Executive Secretary to determine if a source will cause or contribute to a violation of the NAAQS.
14. R307-403-5(1)(b), UAC - Enforceable offsets of 1.2:1 are required for new sources or modifications that would produce an emission increase greater than or equal to 50 tons per year of any combination of PM₁₀, SO₂, and NO_x.
15. R307-403-5(1)(c), UAC - Enforceable offsets of 1:1 are required for new sources or modifications that would produce an emission increase greater than or equal to 25 tons per year but less than 50 tons per year of any combination of PM₁₀, SO₂, and NO_x.
16. R307-405, UAC - Permits: Prevention of Significant Deterioration of Air Quality (PSD)
 - 405-1. Definitions
 - 405-2. Area Designations
 - 405-3. Area Redesignation
 - 405-4. Increments and Ceilings
 - 405-5. Baseline Concentration and Date
 - 405-6. PSD Areas - New Sources and Modifications
 - 405-7. Increment Violations
 - 405-8. Banking of Emission Offset Credit in PSD Areas
17. R307-406, UAC – Visibility
 - 406-1.(1) The Executive Secretary shall review any new major source or major modification proposed in either an attainment area or area of non-attainment area for the impact of its emissions on visibility in any mandatory Class I area.
18. R307-410, UAC - Permits: Emissions Impact Analysis (Air Quality Modeling)
19. R307-413, UAC - Permits: Exemptions and Special Provisions
 - 413-1. Definitions and General Requirements
 - 413-2. Small Source Exemptions - De minimis Emissions
 - 413-3. Flexibility Changes
 - 413-4. Other Exemptions
 - 413-5. Replacement-in-Kind Equipment

- 413-6. Reduction of Air Contaminants
- 413-7. Exemption from Notice of Intent Requirements for Used Oil Fuel Burned for Energy Recovery
- 413-8. De minimis Emissions From Air Strippers and Soil Venting Projects
- 413-9. De minimis Emissions From Soil Aeration Projects.

20. R307-420, UAC - Permits: Ozone Offset Requirements in Davis and Salt Lake Counties.

21. 40 CFR, Part 50 - National Ambient Air Quality Standards (NAAQS). The following areas are Non-attainment areas:

- PM₁₀ Salt Lake and Utah Counties, and the city of Ogden
- SO₂ Salt Lake County and The Oquirrh Mountains above 5,600 feet in Eastern Tooele County
- CO Provo

The following areas are Maintenance Areas:

- Ozone Salt Lake and Davis Counties
- CO Ogden and Salt Lake City

22. 40 CFR 60.15, Definition of Reconstruction - the replacement of components of an existing facility to such an extent that:

- A. The fixed capital cost of the new components exceeds 50% of the fixed capital cost that would be required to construct a comparable entirely new facility and
- B. It is technologically and economically feasible to meet the applicable standards set forth in this part.

<please see following pages for MACT discussion>

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23. Case-by-Case MACT Demonstration

Case-by-Case MACT Demonstration for HAPS

The proposed plant is a major source for emissions of hazardous air pollutants (HAP). The potential HAP emissions from the plant are estimated to be 24.7 tons in aggregate and 16.9 tons of an individual HAP, HCl. Therefore, the plant is subject to case-by-case review under Section 112 (g) of the Clean Air Act for use of Maximum Achievable Control Technology (MACT) to control emissions of HAP, including non-mercury HAP metals, acid gas HAPS including hydrogen chloride and hydrogen fluoride, various organic HAPS including dioxins/furans, and mercury and other metals.

In 2000, EPA carried out an Information Collection Request (ICR) to update the mercury emissions inventory for coal fired power plants in the United States. The outcome of the ICR indicated that some degree of mercury control is achieved by existing conventional air pollution control devices but the capture of mercury varies significantly based on coal and fly ash properties.

The CFB boiler is the principal source of HAP emissions at the proposed plant due to the presence of fluorine, chlorine, mercury, and other heavy metals in the fuel for the boilers.

Case-by-Case MACT for Non-Mercury Metallic HAP Metals

The particulate emissions from the SPC Project will include HAP trace metal emissions from combustion of coal. These HAP metals include antimony, arsenic, beryllium, cadmium, chromium, cobalt, lead, nickel, manganese, and selenium. The control options for non-mercury HAP metals are those identified in the BACT analysis for PM, Section 5.5 of the PSD permit application. The control efficiencies for the non-mercury HAP metals correspond to the control efficiencies discussed for PM. Based on Section 5.5 of the PSD permit application, fabric filtration was chosen as the top control technology form control of PM.

The EPA has established that a PM emission limit is an effective surrogate for individual HAP metal emissions. The EPA has stated that a “strong correlation exists between air emissions of PM and emissions of individual HAP compounds. The control technologies used for the control of PM emissions achieve comparable levels of performance on metallic HAP emissions. Therefore, standards requiring good control of PM will also achieve good control of metallic HAP emissions.”

Hence, fabric filtration by baghouse represents case-by-case MACT for non-mercury metallic HAP metals. The BACT emission limit proposed for PM in the PSD permit application is also proposed as the MACT standard for non-mercury metallic HAP metals.

Case-by-Case MACT for Acid Gas HAPS

Section 5.7 of the PSD permit application states that emission of SO₂ and other acid gases,

such as sulfuric acid mist and hydrogen fluoride (HF), are generated from the release of sulfur present in the fuel. These acid gases will be controlled by the same technology as proposed for SO₂. HCl emissions will also occur as a result of chloride-containing compounds present in the coal. For the SPC Project, HCl and HF are subject to the case-by-case MACT requirement.

For the SPC Project, SO₂ emission control will be accomplished by utilization of limestone injection followed by a circulating dry scrubber. Hence, limestone injection followed by a circulating dry scrubber represents case-by-case MACT for HF and HCl. It is estimated that a reduction of 95% or greater can be achieved by the use of the limestone injection followed by a circulating dry scrubber for acid gas removal.

Case-by-Case MACT for Organic HAPS

As with CO emissions, the rate at which organic compounds are emitted depends on the combustion efficiency of the boiler. Hence, combustion modifications that change combustion residence time, turbulence or temperature may increase or decrease concentrations of organic HAPS found in the flue gas.

Organic emissions include semi-volatile, volatile, and condensable organic compounds with present in the coal or formed as a product of incomplete combustion (PIC). Primarily, organic emissions are characterized by the criteria pollutant class of unburned vapor-phase hydrocarbon which include alkanes, alkenes, aldehydes, alcohols and substituted benzenes (e.g. benzene, toluene, xylene, and ethyl benzene). The remaining organic compounds are almost exclusively classed into a group known as polycyclic organic matter (POM) and a subset of compounds called polynuclear aromatic hydrocarbons (PNA or PAH).

The trace amounts of PIC HAPS that will be emitted will be controlled by implementation of BACT for CO/VOC and PM. This represents case-by-case MACT for organic HAPS. Emissions of polychlorinated dibenzo-p-dioxins and polychlorinated dibenzofurans (PCDD/PCDF) also result from the combustion of coal. Of particular interest are the tetrachloro through octachloro-dioxins and furans. Dioxin and furan emissions are influenced by the extent of destruction of organics during combustion and through reactions in the air pollution control equipment. The formation of PCDD/PCDF in air pollution control equipment is dependant on the flue gas temperature with maximum potential for formation occurring at temperatures of 450 °F to 650 °F.

The formation of dioxin in the CFB boiler will be dependent on the presence of chlorine and complex unburned hydrocarbons that may recombine at a certain temperature as the exhaust gases cool. The presence of chlorine is low in western coals such as those proposed for use by the SPC Project. The ICR database indicates a coal chlorine content of 200 ppm for bituminous coal which is used by the Intermountain Mountain Project (IPP). Since the SPC Project is proposing using coal from the same coal source as IPP, it is reasonable to assume that chlorine concentrations in coal will be low minimizing the potential for dioxin formation. Hence, good combustion controls and fabric filtration represent case-by-case MACT for control of dioxin and organics from the proposed SPC Project.

Case-by-Case MACT for Mercury

The majority of mercury (Hg) in coal exists as sulfur-bound compounds and compounds associated with the organic fraction in coal. Small amounts of elemental Hg may also be present in the coal. There are three basic forms of Hg in the flue gas from a coal-fired electric utility boiler:

- elemental Hg;
- compounds of oxidized Hg (divalent form); and
- particle-bound mercury.

Oxidized mercury compounds in the flue gas from a coal-fired electric utility boiler may include mercury chloride (HgCl₂), mercury oxide (HgO), and mercury sulfate (HgSO₄). The capture of mercury is dependent on the relative amount of mercury species that are present in the flue gas. Particulate bound mercury can be removed in conventional PM emission control devices such as fabric filters and electrostatic precipitators. Compounds of oxidized (divalent form) mercury are generally soluble in water and can be captured in wet scrubbers.

Elemental mercury is insoluble in water and does not react with alkaline reagents used in wet flue gas desulfurization (FGD) systems.

Both the elemental and divalent forms of mercury can be adsorbed onto porous solids such as fly ash or calcium-based acid gas sorbents. Fluidized bed combustion systems typically have high flue gas concentration of high carbon-content fly ash and high levels of mercury capture by PM control devices.

The case-by-case MACT determination for the SPC Project focuses on the application of the best level of mercury control being achieved by similar CFB boilers burning coal, primarily bituminous coal. The application of MACT must determine how the project will obtain a degree of emission reduction that shall not be less stringent than the emission control which is achieved in practice by the best controlled similar source.

Limited mercury data are available for CFB boilers regardless of fuel type. Data from the ICR study identified six (6) facilities with CFB boilers. One CFB boiler used bituminous coal (Stockton Cogen); another CFB boiler used waste bituminous (Scrubgrass Generating Company). The remaining 4 boilers used lignite, waste anthracite or subbituminous coal.

Two (2) facilities (Stockton and AES Hawaii) were reviewed for this MACT analysis since these were the only facilities in the database that used SNCR for NO_x control, sorbent injection such as limestone for SO₂ control used in combination with fabric filters for particulate control. CFB combustion systems typically have high flue gas concentrations of high-carbon-content fly ash and high levels of mercury capture in PM emission control devices.

A fabric filter was determined to represent the best control technology for control of mercury from the combustion of bituminous western coal and is the control technology proposed for the SPC Project. Currently, the literature suggests that there are no available commercial control technologies designed exclusively for mercury control from coal-fired power plants. Existing technologies to control PM and SO₂ have the added ability to control mercury. The injection of activated carbon into new particulate control devices (such as a

baghouse) offers some promise in reducing mercury emissions. Short-term tests have shown a reduction of up to 90% for mercury from bituminous coals but these tests also indicated that such high levels of control may not be achievable over long periods.

Required Data for 40 CFR 63.43

40 CFR 63.43 contain the application requirements for a case-by-case MACT determination. The following information to be presented includes:

- *The name and address (physical location) of the major source to be constructed or reconstructed.*

The SPC Project is proposed to be located near Sigurd, in Sevier County. The SPC Project is a major source of HAPS with estimated emissions to be greater than 10 tons for HCl.

- *A brief description of the major source to be constructed or reconstructed and identification of any listed source category or categories in which it is included.*

The proposed SPC Project consists of a coal-fired atmospheric circulating fluidized bed combustion unit which is proposed to have a maximum heat input of 2532 mmBtu/hr with a capacity of 270 megawatts. The applicable source category is utility steam-electric generating units.

- *The expected commencement date for the construction or reconstruction of the major source.*

Construction of the facility will begin when the appropriate permits are obtained in 2004.

- *The expected completion date for construction or reconstruction of the major source.*

Construction is anticipated to take 4 years (2008).

- *The anticipated date of start-up for the construction or reconstructed major source.*

Startup of the proposed facility is anticipated to begin in 2008.

- *The HAP emitted by the constructed or reconstructed major source, and the estimated emission rate for each such HAP, to the extent this information is needed by the permitting authority to determine MACT.*

The source of the HAP emissions will be the boiler exhaust stack. The estimated HAP emissions are presented in Attachment B (Notice of Intent addendum letter dated December 5, 2003). These emission estimates were obtained from factors presented in AP-42, Section 1.1.

- *Any federally enforceable emission limitations applicable to the constructed or reconstructed major source.*

Federally enforceable emission limitations will be established in the PSD permit as BACT requirements (see sections III and V of this engineering review). Other applicable regulations include 40 CFR 72-75, 40 CFR 70, and 40 CFR 60 Subpart Da.

- *The maximum and expected utilization of capacity of the constructed or reconstructed source, and the associated uncontrolled emission rates for that source, to the extent this*

information is needed by the permitting authority to determine MACT.

The maximum and expected utilization of the constructed source is anticipated to be greater than 90%. The HAP emission rates presented in Attachment B (Notice of Intent addendum letter dated December 5, 2003) were based on a 100 percent capacity factor. Uncontrolled emissions for HCl are estimated to be 133.8 lb/hr or 561.9 tons/yr.

• *The controlled emissions for the constructed or reconstructed major source in tons per year at expected and maximum utilization of capacity, to the extent this information is needed by the permitting authority to determine MACT.*

The controlled emissions of HCl are based on a 100-percent capacity factor and are estimated to be 4.0 lb/hr or 16.9 tons per year assuming a control device efficiency of 97%.

• *A recommended emission limitation for the constructed or reconstructed major source consistent with the principles set forth in paragraph (d) of this section.*

Listed below are the recommended emissions limits for each category of HAPs.

1) Non-mercury metallic HAP - PM was used as the surrogate pollutant. The proposed emission rate for non-mercury metallic HAP is 0.02 lb/mmBtu.

2) Acid Gas HAP - SO₂ was used as the surrogate pollutant. The proposed controlled emission rate for HCl is 4.0 lb/hr. For fluorides, the proposed emission rate is 0.000191 lb/mmBtu. The proposed HF and H₂SO₄ emission rates are 0.005 lb/mmBtu and 0.0024 lb/mmBtu, respectively.

3) Organics - CO was used as the surrogate pollutant.

4) Mercury - SO₂ and PM are the surrogates for mercury. The proposed emission limit for mercury is 0.000004 lb/mmBtu.

• *The selected control technology to meet the recommended MACT emission limitation, including technical limitation on the design, operation, size, estimated control efficiency of the control technology.*

MACT for HAPs from the SPC Project burning western bituminous coal is to be the control technology capable of demonstrating BACT for SO₂, PM₁₀, and CO. A description of the proposed control technology is found in Section 5 of the PSD permit application.

• *Supporting documentation including identification of alternative control technologies considered, and analysis of non-air quality health environmental impacts or energy requirements for the selected control technology.*

The project is considered BACT for SO₂, CO, VOC, and PM₁₀. Fabric filtration was chosen as the most stringent control that has been demonstrated on CFB boilers for mercury removal. Less effective control technologies would not satisfy BACT so no alternative control technologies were considered.

• *Any other relevant information required pursuant to subpart A.*

No other relevant information was identified.

MACT Compliance

Fabric filters has been determined as MACT for trace non-mercury metals and mercury from the combustion of bituminous coal. Compliance will be demonstrated by proper

operation of the fabric filters. Compliance with the PM and PM10 emission limits will be proposed in a Compliance Assurance Monitoring (CAM) protocol which will be developed for this project. Adherence to the CAM will insure that the air pollution control equipment is working to design efficiency and that pollutant emission limits are being achieved.

For organic and acid gas HAPS, compliance for MACT will be based on good combustion controls and efficient operation of the SO2 control equipment.

V. RECOMMENDED APPROVAL ORDER CONDITIONS

General Conditions:

1. This Approval Order (AO) applies to the following company:

Site Office

Sevier Power Company, LLC
1200 West Substation Road
Sigurd, Utah 84657

Corporate Office Location

NEVCO Energy Company, LLC
620 South Main Street
Bountiful, Utah 84010

Phone Number (801) 298-5000

Fax Number (801) 298-7333

The equipment listed in this AO shall be operated at the following location:

1200 West Substation Road, Sigurd, Utah 84657

Universal Transverse Mercator (UTM) Coordinate System: UTM Datum NAD27
4,299.9 kilometers Northing, 414.9 kilometers Easting, Zone 12

2. All definitions, terms, abbreviations, and references used in this AO conform to those used in the Utah Administrative Code (UAC) Rule 307 (R307) and Title 40 of the Code of Federal Regulations (40 CFR). Unless noted otherwise, references cited in these AO conditions refer to those rules.
3. The limits set forth in this AO shall not be exceeded without prior approval in accordance with R307-401.
4. Modifications to the equipment or processes approved by this AO that could affect the emissions covered by this AO must be reviewed and approved in accordance with R307-401-1.
5. All records referenced in this AO or in applicable NSPS or MACT standards, which are required to be kept by the owner/operator, shall be made available to the Executive Secretary or Executive Secretary's representative upon request, and the records shall include the five-year period prior to the date of the request. Records shall be kept for the following minimum periods:
- A. Emission inventories Five years from the due date of each emission statement or until the next inventory is due, whichever is longer.
 - B. All other records Five years
6. Sevier Power Company, LLC (SPC) shall install and operate the 270 MW CFB Boiler and associated equipment and shall conduct its operations of same in accordance with the terms

and conditions of this AO, which was written pursuant to SPC's Notice of Intent submitted to the Division of Air Quality (DAQ) on January 29, 2003 and additional information submitted to the DAQ on April 16, 2003, July 2, 2003, September 10, 2003, October 31, 2003, December 5, 2003 and February 25, 2004.

7. The approved installations shall consist of the following equipment or equivalent*:
 - A. Coal Handling Equipment
 - Coal storage pile
 - Five (5) coal storage silos
 - Coal truck unloading hopper
 - Coal crushing building
 - Coal transfer conveyors
 - B. Lime Handling Equipment
 - Lime storage silo
 - Lime conveyor
 - C. Limestone Handling Equipment
 - Limestone storage silo
 - Limestone conveyor
 - D. Ash Storage and Handling
 - Two (2) ash storage silos
 - Ash pickups
 - Ash conveyors
 - Truck transfer points
 - E. Circulating Fluidized Bed Combustor
 - Drum type CFB boiler
 - Fluidized bed heat exchangers
 - Natural gas startup burners
 - Air-cooled condenser**
 - Stack (at least 460 feet in height as measured from base of stack)
 - F. Control Equipment
 - Induced draft baghouses and cartridge-type particulate filters at all material transfer points
 - Silo baghouses
 - Ash recycle cyclones**
 - Dry-lime scrubber
 - Selective non-catalytic reduction (using)
 - Ammonia injection system with ammonia storage tank
 - Primary stack baghouse
 - G. Steam System**
 - Water treatment**

Turbine generator**
Air heater**

- H. Associated Equipment
 - Diesel-fired emergency fire pump
 - Diesel-fired emergency generator
 - Diesel storage tanks

* Equivalency shall be determined by the Executive Secretary.

** This equipment is listed for informational purposes only. There are no emissions from this equipment.

- 8. A manometer or magnehelic pressure gauge shall be installed to measure the differential pressure across the main stack fabric filter (baghouse). Static pressure differential across the fabric filter shall be between 0.5 to 12 inches of water column. The pressure gauge shall be located such that an inspector /operator can safely read the indicator at any time. The reading shall be accurate to within plus or minus 1.0 inches water column. The instrument shall be calibrated according to the manufactures instructions at least once every 12 months. Continuous or intermittent recording of the reading is not required.
- 9. SPC shall notify the Executive Secretary in writing when the installation of the equipment listed in Condition #7 has been completed and is operational, as an initial compliance inspection is required. To insure proper credit when notifying the Executive Secretary, send your correspondence to the Executive Secretary, attn: Compliance Section.

If construction and/or installation has not been completed within eighteen months from the date of this AO, the Executive Secretary shall be notified in writing on the status of the construction and/or installation. At that time, the Executive Secretary shall require documentation of the continuous construction and/or installation of the operation and may revoke the AO in accordance with R307-401-11.

Limitations and Tests Procedures

- 10. Emissions to the atmosphere at all times from the indicated emission point(s) shall not exceed the following rates and concentrations:

Source: (main boiler stack)

<u>Pollutant</u>	<u>lb/mmBTU</u>	<u>Averaging Period</u>
SO ₂	0.05	24-hour rolling
SO ₂	0.022	30-day rolling
NO _x	0.1	24-hour rolling
H ₂ SO ₄	0.0024	24-hour rolling

Source: (main boiler stack)

<u>Pollutant</u>	<u>lb/hr</u>	<u>Averaging Period</u>
PM ₁₀	39.0	24-hour rolling
CO.....	292.0	1-hour

11. Stack testing to show compliance with the emission limitations stated in the above condition shall be performed as specified below:

<u>Emissions Point</u>	<u>Pollutant</u>	<u>Testing Status</u>	<u>Test Frequency</u>
(main boiler stack)	PM ₁₀	*	&
	SO ₂	*	#
	NO _x	*	#
	CO	*	#
	H ₂ SO ₄	*	@

B. Testing Status (To be applied to the source listed above)

* Initial compliance testing is required. The initial test date shall be performed as soon as possible and in no case later than 180 days after the start up of a new emission source, an existing source without an AO, or the granting of an AO to an existing emission source that has not had an initial compliance test performed. If an existing source is modified, a compliance test is required on the modified emission point that has an emission rate limit.

@ Test every five years. The Executive Secretary may require testing at any time.

& Test every year. The Executive Secretary may require testing at any time.

Compliance shall be demonstrated through use of a Continuous Emissions Monitoring System (CEM) as outlined in Condition #22 below. The Executive Secretary may require testing at any time.

C. Notification

The Executive Secretary shall be notified at least 30 days prior to conducting any required emission testing. A source test protocol shall be submitted to DAQ when the testing notification is submitted to the Executive Secretary.

The source test protocol shall be approved by the Executive Secretary prior to performing the test(s). The source test protocol shall outline the proposed test methodologies, stack to be tested, and procedures to be used. A pretest conference shall be held, if directed by the Executive Secretary.

D. Sample Location

The emission point shall be designed to conform to the requirements of 40 CFR 60, Appendix A, Method 1, or other methods as approved by the Executive Secretary. An Occupational Safety and Health Administration (OSHA) or Mine Safety and Health Administration (MSHA) approved access shall be provided to the test location.

E. Volumetric Flow Rate

40 CFR 60, Appendix A, Method 2 or other testing methods approved by the Executive Secretary.

F. PM₁₀

For stacks in which no liquid drops are present, the following methods shall be used: 40 CFR 51, Appendix M, Methods 201, 201a, or other testing methods approved by the Executive Secretary. The back half condensibles shall also be tested using the method specified by the Executive Secretary. All particulate captured shall be considered PM₁₀.

For stacks in which liquid drops are present, methods to eliminate the liquid drops should be explored. If no reasonable method to eliminate the drops exists, then the following methods shall be used: 40 CFR 60, Appendix A, Method 5, 5a, 5d, or 5e as appropriate, or other testing methods approved by the Executive Secretary. The back half condensibles shall also be tested using the method specified by the Executive Secretary. The portion of the front half of the catch considered PM₁₀ shall be based on information in Appendix B of the fifth edition of the EPA document, AP-42, or other data acceptable to the Executive Secretary.

The back half condensibles shall not be used for compliance demonstration but shall be used for inventory purposes.

G. Sulfur Dioxide (SO₂)

40 CFR 60, Appendix A, Method 6, 6A, 6B, 6C, or other testing methods approved by the Executive Secretary.

H. Nitrogen Oxides (NO_x)

40 CFR 60, Appendix A, Method 7, 7A, 7B, 7C, 7D, 7E, or other testing methods approved by the Executive Secretary.

I. Sulfuric Acid (H₂SO₄)

The test method shall be submitted for approval or may be assigned by the Executive Secretary.

J. Carbon Monoxide (CO)

40 CFR 60, Appendix A, Method 10, or other testing methods approved by the Executive Secretary.

K. Calculations

To determine mass emission rates (lb/hr, etc.) the pollutant concentration as determined by the appropriate methods above shall be multiplied by the volumetric flow rate and any necessary conversion factors determined by the Executive Secretary, to give the results in the specified units of the emission limitation.

L. New Source Operation

For a new source/emission point, the production rate during all compliance testing shall be no less than 90% of the production rate listed in this AO. If the maximum AO allowable production rate has not been achieved at the time of the test, the following procedure shall be followed:

- 1) Testing shall be at no less than 90% of the production rate achieved to date.
- 2) If the test is passed, the new maximum allowable production rate shall be 110% of the tested achieved rate, but not more than the maximum allowable production rate. This new allowable maximum production rate shall remain in effect until successfully tested at a higher rate.
- 3) The owner/operator shall request a higher production rate when necessary. Testing at no less than 90% of the higher rate shall be conducted. A new maximum production rate (110% of the new rate) will then be allowed if the test is successful. This process may be repeated until the maximum AO production rate is achieved.

M. Existing Source Operation

For an existing source/emission point, the production rate during all compliance testing shall be no less than 90% of the maximum production achieved in the previous three (3) years.

12. Visible emissions from all emission points shall not exceed 20% opacity. Opacity observations of emissions from stationary sources shall be conducted according to 40 CFR 60, Appendix A, Method 9. For sources that are subject to NSPS, opacity shall be determined by conducting observations in accordance with 40 CFR 60.11(b) and 40 CFR 60, Appendix A, Method 9.
13. Initial testing for HCl, HF, fluorides, lead (Pb) and mercury (Hg) is required within 180 days of commencing operation. Testing shall be performed using the following methods for verification of BACT.

Emission	Testing Method*	BACT Design Rate
HCl	40 CFR 60, Appendix A, Method 26A	4.01 lb/hr
HF	40 CFR 60, Appendix A, Method 26A	0.005 lb/mmBtu
Fluorides	40 CFR 60, Appendix A, Method 13A	0.00019 lb/mmBtu
Mercury (Hg)	40 CFR 60, Appendix A, Method 29	0.000004 lb/mmBtu

* or other testing methods approved by the Executive Secretary

14. Visible fugitive dust emissions from haul-road traffic and mobile equipment in operational areas shall not exceed 20% opacity. Visible emissions determinations for traffic sources shall use procedures similar to Method 9. The normal requirement for observations to be made at 15-second intervals over a six-minute period, however, shall not apply. Six points, distributed along the length of the haul road or in the operational area, shall be chosen by the Executive Secretary or the Executive Secretary's representative. An opacity reading shall be made at each point when a vehicle passes the selected points. Opacity readings shall be made 1/2 vehicle length or greater behind the vehicle and at approximately 1/2 the height of the vehicle or greater. The accumulated six readings shall be averaged for the compliance value.
15. The following production and/or consumption limits shall not be exceeded:
- A. 1,000,000 tons of coal burned per rolling 12-month period
 - B. 2,700 tons of coal burned per day based on a 24-hour rolling average
 - C. 4,000 gallons of diesel burned per rolling 12-month period
- To determine compliance with a rolling 12-month total the owner/operator shall calculate a new 12-month total by the twentieth day of each month using data from the previous 12 months. Records of consumption/production shall be kept for all periods when the plant is in operation. Production/consumption shall be determined by an operations logbook. The records of consumption/production shall be kept on a daily basis. Hours of operation shall be determined by supervisor monitoring and maintaining of an operations log.
16. The emergency generator shall be used for electricity producing operation only during periods when electric power from the public utilities is interrupted, or for regular maintenance of the generator. Records documenting generator usage shall be kept in a log and they shall show the date the generator was used, the duration in hours of the generator usage, and the reason for each usage.
17. The diesel driven fire pump shall be operated on an emergency basis only, except for routine engine and fire system maintenance and training. Records documenting diesel driven fire pump usage shall be kept in a log and shall show the date the pump was used, the duration in hours of use, and the reason for each usage.

Roads and Fugitive Dust

18. The facility shall abide by all applicable requirements of R307-205 for Fugitive Emission and Fugitive Dust sources.

Fuels

19. SPC shall use coal as a primary fuel and natural gas as a startup fuel in the CFB boiler. The emergency generators and diesel-driven fire pumps shall use only #2 fuel oil as fuel.
20. The mercury content of any coal burned in any fuel burning process shall be monitored and recorded for each load of fuel delivered. Certification of fuels shall be either by Sevier Power Company's own testing or test reports from the fuel marketer.

For determining mercury content in coal, American Society for Testing and Materials (ASTM) Method D3684-01 or other method approved by the Executive Secretary, is to be used.

21. The sulfur content of any coal burned in any fuel burning or process installation not covered by New Source Performance Standards for sulfur emissions shall contain no more than 1.0 pound sulfur per million gross Btu heat input for any mixture of coal. Similarly, the sulfur content of any fuel oil combusted shall not exceed 0.5% by weight.

The sulfur content shall comply with all applicable sections of R307-203. Certification of fuels shall be either by Sevier Power Company's own testing or test reports from the fuel marketer. Records of fuel supplier's test report on sulfur content shall be available on-site for each load delivered.

Methods for determining sulfur content of coal shall be those methods of the American Society for Testing and Materials R307-203-1(4)

- A. For determining sulfur content in coal, ASTM Methods D3177-75 or D4239-85 are to be used.
- B. For determining the gross calorific (or Btu) content of coal, ASTM Methods D2015-77 or D3286-85 are to be used.
- C. The sulfur content of fuel oil shall be determined by ASTM Method D-4294-89 or approved equivalent. Certification of fuel oil shall either be by SPC's own testing or test reports from the fuel oil marketer.

Federal Limitations and Requirements

22. In addition to the requirements of this AO, all applicable provisions of 40 CFR 60, New Source Performance Standards (NSPS) Subpart A, 40 CFR 60.1 to 60.18 and Subpart Da, 40 CFR 60.40a to 60.49a (Standards of Performance for Electric Utility Steam Generating Units for Which Construction in Commenced After September 18, 1978) and Subpart Y 40 CFR 60.250 to 60.254 (Standards of Performance for Coal Preparation Plants) apply to this

installation.

23. In addition to the requirements of this AO, all applicable provisions of 40 CFR 72, 73, 75, 76, 77 and 78 – Federal regulations for the Acid Rain Program under Clean Air Act Title IV apply to this installation.

Monitoring - Continuous Emissions Monitoring

24. SPC shall install, calibrate, maintain, and operate a continuous emissions monitoring system on the main boiler stack. SPC shall record the output of the system, for measuring the SO₂ emissions, the NO_x emissions and the CO emissions. The monitoring system shall comply with all applicable sections of R307-170; 40 CFR 60.13; and 40 CFR 60, Appendix B.

All continuous emissions monitoring devices as required in federal regulations and state rules shall be installed and operational prior to placing the affected source in operation.

Except for system breakdown, repairs, calibration checks, and zero and span adjustments required under paragraph (d) 40 CFR 60.13, the owner/operator of an affected source shall continuously operate all required continuous monitoring systems and shall meet minimum frequency of operation requirements as outlined in 40 CFR 60.13 and Section R307-170.

Records & Miscellaneous

25. At all times, including periods of startup, shutdown, and malfunction, owners and operators shall, to the extent practicable, maintain and operate any equipment approved under this Approval Order including associated air pollution control equipment in a manner consistent with good air pollution control practice for minimizing emissions. Determination of whether acceptable operating and maintenance procedures are being used will be based on information available to the Executive Secretary which may include, but is not limited to, monitoring results, opacity observations, review of operating and maintenance procedures, and inspection of the source. All maintenance performed on equipment authorized by this AO shall be recorded.
26. The owner/operator shall comply with R307-150 Series. Inventories, Testing and Monitoring.
27. The owner/operator shall comply with R307-107. General Requirements: Unavoidable Breakdowns.

The Executive Secretary shall be notified in writing if the company is sold or changes its name.

Under R307-150-1, the Executive Secretary may require a source to submit an emission inventory for any full or partial year on reasonable notice.

This AO in no way releases the owner or operator from any liability for compliance with all other applicable federal, state, and local regulations including R307.

A copy of the rules, regulations and/or attachments addressed in this AO may be obtained by contacting the Division of Air Quality. The Utah Administrative Code R307 rules used by DAQ, the Notice of Intent (NOI) guide, and other air quality documents and forms may also be obtained on the Internet at the following web site:

<http://www.airquality.utah.gov/>

The annual emissions estimations below are for the purpose of determining the applicability of Prevention of Significant Deterioration, non-attainment area, Maintenance area, and Title V source requirements of the R307. They are not to be used for determining compliance.

The Potential To Emit (PTE) emissions for this source are currently calculated at the following values:

<u>Pollutant</u>	<u>Actual Emissions tons/year</u>	<u>Requested PTE Increase tons/year</u>	<u>Actual to Potential Increase tons/year</u>	<u>Total PTE Emissions tons/year</u>
PM ₁₀	0.00	177.4	177.4	177.4
SO ₂	0.00	0.00	547.3	547.3
NO _x	0.00	1066.6	1066.6	1066.6
CO	0.00	1278.6	1278.6	1278.6
VOC	0.00	53.4	53.4	53.4
HAPs				
HCL	0.00	16.9	16.9	16.9
Total HAPs	0.00	24.7	24.7	24.7